Service Date: July 5, 1984

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

IN THE MATTER of the Application of	)	UTILITY DIVISION
MONTANA-DAKOTA UTILITIES CO.	)	
to Adopt Increased Rates for Electric	)	DOCKET NO. 83.9.68
Service in the State of Montana.	)	ORDER NO. 5036a

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APPEARANCES

FOR THE APPLICANT:

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FOR THE MONTANA CONSUMER COUNSEL:

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John C. Allen, Consumer Counsel Staff Attorney, 34 West Sixth Avenue, Helena, Montana 59620, appearing on behalf of the consuming public of the State of Montana

FOR THE COMMISSION:

Robert Nelson, Staff Attorney

BEFORE:

THOMAS J. SCHNEIDER, Chairman
HOWARD L. ELLIS, Commissioner
DANNY OBERG, Commissioner

FINDINGS OF FACT

PART A

1. On September 30, 1983, the Montana-Dakota Utilities Company (MDU, the Company or Applicant) filed an application with the Commission seeking a general rate increase for electric service. MDU requested an annual increase in revenues in the amount of $8,731,439.

2. Included in the September 30th filing was a request for interim relief in the amount of $2,972,304. On December 12, 1983, the Commission granted an interim increase of $2,808,422 in Order No. 5036.

3. On October 13, 1983, the Commission published notice of the application and a proposed procedural schedule. Detailed Proposed Procedural Orders were individually served on parties to the last MDU rate case and the service list submitted with the application. After considering requested amendments, the Commission issued a final Procedural Order on November 7, 1983.

4. Upon petition, intervenor status was granted to the Montana Consumer Counsel (MCC).

5. On January 12, 1984, MCC moved to amend the Procedural Order to postpone hearings in Docket Nos. 83.9.68 and 83.8.58, or in the alternative, to strike all testimony of MDU witness Dr. Dennis B. Fitzpatrick. On January 20, 1984, the Commission denied MCC's above described motion.

6. Also on January 20, 1984, the Commission denied MDU's motion to compel MCC witness, Dr. John W. Wilson, to provide more detailed responses to Data Request Nos. 1 and 3, and directed 'tine parties to brief the matter of supporting regulatory decisions in initial post-hearing briefs.

7. Following issuance of notice, the hearing on MDU's application in this Docket commenced at 9:00 a.m. on January 31, 1984, concluding on the same day, at the Miles Community College, Room 106, Miles City, Montana. Public hearings for the convenience of the public were also held at 7:00 p . m., January 31, 1984 at the same location, as well as at the following times and places:

Glendive: February 7, 1984, 10:00 a.m. in the Community Room of the Dawson County Courthouse;

Sidney: February 7, 1984, 7:00 p.m. in the basement of the Sidney Public Library;

Culbertson: February 8 , 1984 , 7:00 p . m . in the cafeteria of the Culbertson elementary school;

Plentywood: February 9, 1984, 9:00 a.m. in the courtroom of the Sheridan County Courthouse;

Scobey: February 9, 1984, 1:00 p.m. in the courtroom of the Daniels County Courthouse;

Wolf Point: February 9, 1984, 7:30 p.m. in the courtroom of the Roosevelt County Courthouse; and

Glasgow: February 10, 1984, 10:00 a.m. in the courtroom of the Valley County Courthouse.

PART B

CAPITAL STRUCTURE AND ASSOCIATED COSTS

Capital Structure

8. Applicant's witness, Mr. John Renner, in his pre-filed testimony, presented a utility capital structure as anticipated at September 30, 1983. During the hearing, Mr. Renner presented the actual September 30, 1983, utility capital structure.

9. Applicant proposed the following capital structure and associated costs, as implied by Mr. Renner's gas capital structure and costs update (TR, p. 198).

Description	Ratio	Cost	Weighted Cost
Long-Term Debt	45.802%	8.714%	3.991%
Preferred Stock	14.994	8.793	1.318
Common Equity	39.204	15.500	6.077
Total	100.000%		11.386%

10. Dr. Caroline Smith, expert witness for the Montana Consumer Counsel, in her testimony proposed an allocated electric utility capital structure as of September 30, 1983. Dr. Smith adjusted her capital structure to eliminate nonutility and gas operations.

11. MCC proposed the following capital structure and associated costs (MCC Exh. 3A, Exh. CMS-1):

Description	Ratio	Cost	Weighted Cost
Long-Term Debt	49.21%	8.75%	4.31%
Preferred Stock	14.05	8.79	1.24
Common Equity	36.74	13.00	6.78
Total	100.000%		10.33%

12. Prior to the first witness coming to the stand during the hearing, all parties stipulated into evidence in this proceeding various testimonies from witnesses heard during the gas hearing in Docket No. 83.8.58. Among those witnesses whose testimony and exhibits were stipulated into the record were MDU witnesses Renner and Fitzpatrick and MCC witness Smith (TR, pp. 20-23). The Commission finds this procedure to be proper in this proceeding and will refer to various segments of the testimonies of the above witnesses, given for Docket No. 83.8.58, throughout Part B of this order.

Allocation Factors and Procedures

13. In Order No. 4834c of Docket No. 81.7.62, because some confusion had existed surrounding the proper approach to be used in determining MDU's capital structure amounts for the gas and electric utilities, the Commission provided an explanation of the proper allocation procedure:

> Starting with the consolidated MDU company's common equity, investment in all nonutility subsidiaries is deducted, which leaves utility common equity. The ratio of gross gas utility plant plus gas construction work in progress to total gross utility plant plus total utility construction work in progress is then applied to total utility common equity to determine the portion attributable to the gas utility. The same ratio is applied to total utility preferred stock. The ratio is

> also applied to utility debt, but only after REA mortgage notes and pollution control debt are allocated directly to the electric utility. The same procedure should be used in computing the electric utility capital structure. (Order No. 4834c, Finding of Fact No . 55)

14. In this Docket, MDU and MCC have again used different allocation factors. Mr. Renner's allocation calculation was done with data for net plant, construction work in progress, and gas in storage. Dr. Smith's allocation factor was calculated from data for gross plant plus construction work in progress as of September 30, 1983. (MCC Exh. 3A, p. 8)

15. During cross-examination by Mr. Nelson of the Commission, Dr. Smith discussed the appropriateness of her proposed allocation factors:

> Q. I believe you were explaining the difference between your allocation and methodology and the Company's.
>
> A. Yes, the allocation factors I discussed in my electric testimony -- The allocation factors that we factor are done differently. Mine are gross plant plus CWIP as of September 30, which is the date of my capital structure. My Renner's allocation was done on the basis of net plant plus CWIP plus gas in storage. I don't have gas in storage in my calculation at all.
>
> It seems to me that when the Company sells securities, those are associated with facilities that are put on line which, in effect, go into the gross-plant account on the assets side of the balance sheet. That's what those securities are supporting, and that's the major component of the assets that are used and useful.
>
> There is an argument for using net instead of gross on the theory that depreciation is collected to replace -or displace previously sold securities and allow them to fund new assets. I think between gross and net plant, probably either one of those things could be done.
>
> I'm less comfortable with the use of gas in storage just because it's not real obvious to me that that's some thing that could be used to secure securities, but I suppose if you were to find out different from that, you might want to rethink Mr.

> Renner's proposal as opposed to the one that I followed. (TR, pp. 330-331)

16. Concerning the matter of whether to use gross plant plus CWIP or net plant plus CWIP in determining proper allocation factors between MDU's gas and electric capital structures, the Commission agrees with Dr. Smith that generally either formula could be appropriate. However, since the Commission has consistently approved the gross plant plus CWIP method, as proposed by MCC, the Commission believes that continuance of that approach would be proper to provide smooth flow from case to case while protecting against "slippage through the cracks."

17. Regarding the inclusion of gas in storage in the allocation formula, the Commission agrees with Dr. Smith that since gas in storage cannot be used to secure securities, gas in storage should not be included in the allocation formula. The Commission, therefore, finds the MCC proposed electric allocation factor of 55.18 percent to be proper in this proceeding.

18. In the current Docket, MDU chose not to adhere to the allocation procedure described above in Finding of Fact No. 13. Instead, the Company proposed an electric capital structure which would be identical to its gas capital structure. The total amount of long-term debt, thus, includes approximately $32 million of directly assignable electric utility debt (MDU Exh. B, St. F, p. 1 of 3).

19. MCC witness Dr. Smith proposed to allocate long-term debt in the manner supported by the Commission in the last MDU general gas case, Order No. 4918b of Docket No. 82.6.40. Dr. Smith first made direct assignments (for both nonutility equity capital and electric-identified long-term debt) and then allocated the remaining common utility debt between electric and gas operations based on the electric allocation factor of 55.18 percent (MCC Exh. 1 of Docket No. 83.8.58, Exh. CMS-11, p. 1 of 2).

20. The Commission believes that directly assignable debt should be matched with the utility capital structure to which the proceeds can be traced. The remaining common utility debt should then be allocated between gas and electric according to the ratio described in Finding of Fact No. 13. The Commission, therefore, determines Dr. Smith's procedure for allocating long-term debt to be proper in this proceeding. The following table shows the proper computation of the approved amount of long-term debt in this proceeding in the amount of $111,459,000:

(000)

First Mortgage Bonds	$ 89,775
Sinking Fund Bonds	54,583
Total Common Utility Debt	$144,358*
Electric Allocation Factor	x .5518
Electric Portion	$ 79,657
Add: Directly Assignable Electric Debt	31,802
Total Electric Long-Term Debt	$111,459

* Excludes $31,802,000 of pollution control and REA debt, which is directly assignable to electric utility.

21. Concerning the amount of preferred stock and common equity, the allocation factor of 55.18 percent must be applied to the total utility figures to determine the proper amounts in the capital structure. MDU and MCC agreed upon the proper amounts of unallocated preferred stock and common equity in MCC Exh. 3A, Exh. CMS-1. The Commission, therefore, determines the proper amount of allocated preferred stock in this proceeding to be $31,823,000 and the proper amount of allocated common equity to be $83,202,000, excluding MDU's equity investment in subsidiaries.

Cost of Capital

Preferred Stock

22. The cost of preferred stock is not a controverted issue in this case. The cost of preferred stock is based on the embedded cost of preferred shares outstanding at September 30, 1983, and has been determined to be 8.79 percent by the Applicant and MCC (TR, p. 198). This cost is acceptable to the Commission.

Long-Term Debt

23. Dr. Smith of MCC included one year's amortization of gain from reacquired debt as of September 30, 1983, as a deduction to interest expense. The Company also included amortization of the gain as a reduction of interest expense. Mr. Renner explained in his rebuttal testimony that the amortization of the gain on reacquired debt is being deducted from the cost of debt, thereby reducing the embedded debt cost and passing this gain on to the customer (MDU Exh. HH, p. 2?. The Company disagreed with also giving the customer favored treatment as to the unamortized portion of the gain, as will be discussed in the rate base portion of this Order.

24. The Commission agrees with Dr. Smith and the Company that the amortization of the gain from reacquired debt should serve as a reduction to interest expense for long-term debt. This treatment. allows customers to be compensated, as they paid the interest on the bonds while they were outstanding. As shown on Exh. B, St. F, Rule 38.5.147, page 1 of 3, the Company has offset long-term debt interest expense with amortization of the gain from reacquired debt. The Commission determines, therefore, that the amortization of gain from reacquired debt as an offset to debt expense is appropriate in this Docket.

25. Pursuant to the previous discussion of the proper amount of long-term debt in Finding of Fact Nos. 18 through 20, the Commission determines the proper cost of long-term debt to be 8.75 percent in this proceeding, as calculated below:

	Amount (000)	Annual Cost (000)
First Mortgage Bonds	$ 89,775	$ 7,785
Sinking Fund Bonds	54,583	5,251*
Total Utility	$144,358	$13,036
Electric Allocation Factor	x .5518	x .5518
Electric Portion of Common Utility	$ 79,657	$ 7,193
Electric Directly Assignable Debt	31,802	2,554
Total Electric Utility	$111,459	$ 9,747
Cost of Electric Long-Term Debt	8.75%	

* Includes amortization of gain from reacquired debt as a deduction to interest expense.

Common Equity

<u>Applicant</u>

26. Based on the testimonies of Mr. William Glynn and Dr. Dennis Fitzpatrick, Mr. John Renner proposed a cost of common equity of 15.5 percent. Dr. Fitzpatrick performed an updated study for his rebuttal testimony, and he found that since the time of his original study in early September of 1983, MDU's cost of equity capital in January of 1984 was between 15 and 18 percent (MDU Exh. JJ, pp. 4-5). MDU thereafter, however, did not modify its application to seek a return on equity greater than 15.5 percent.

27. Dr. Fitzpatrick's determination of MDU's cost of common equity capital was based on three separate studies: (1) the equity-debt risk premia approach; (2) a descriptive study of the financial performance of MDU and comparable risk companies; and (3) the discounted cash flow (DCF) method (MDU Exh. II, p. 6). The result of each of these studies supported Dr. Fitzpatrick's original conclusion that MDU's cost of equity is not less than the 15.5-17 percent range, and supported his updated conclusion that MDU's cost of common equity capital is between 15 and 18 percent as of January, 1984 (MDU Exh . JJ, p . 4).

28. In his equity-debt risk premia approach, Dr. Fitzpatrick examined the return/risk relationship of MDU's common stock vis-a-vis alternative investment opportunities. One of the major premises in this analysis is that the cost of common equity capital is never less than the incremental cost of a utility's long-term debt (MDU Exh. II, p. 11). In his testimony, Fitzpatrick testified:

> The implications of this equity-debt risk premia analysis are clear. First, MDU's cost of common equity is currently not less than 13.50%. Second, a very conservative estimate of MDU's equity risk premium is from 3 to 4%.... Given the incremental cost of MDU's long-term debt in September, 1983 and my estimate of MDU's minimum equity risk premium, the equity-debt risk premia approach indicates that MDU's cost of common equity is between 16.50% and 17.50%. . .
>
> (MDU Exh. II, pp. 17-18)

Comparatively, in his rebuttal testimony, Dr. Fitzpatrick determined that the equity-debt risk premia approach indicated that MDU's updated cost of common equity capital is between 16.5 and 17.5%. (MDU Exh. JJ, p. 3)

29. In his comparison of comparable risk companies, Dr. Fitzpatrick first analyzed MDU's overall financial performance since 1971 and then compared that data to the four sets of companies that he felt have exhibited business and financial risk characteristics generally similar to the risk associated with MDU's electric utility operations. Dr. Fitzpatrick estimated the average cost of common equity for each of the four samples with the market valuation modeling approaches. Fitzpatrick believed that the results of those analyses confirmed the risk comparativeness of those utilities with MDU.

30. In his market valuation modeling approach, Dr. Fitzpatrick developed a model to show the relationship between a sample of firms' market to book value ratios, average annual price/earnings ratios, and other financial data, and from that he determined the sample's average cost of common equity capital (MDU Exh. II, p. 27). He concluded that his analysis of the financial performance of those comparable companies demonstrates that MDU's consolidated equity returns are approaching the Company's actual market cost of common equity for the first time in years and that this study showed MDU's cost of equity capital to be between 16 and 17 percent (MDU, Exh. II, p. 29).

31. Dr. Fitzpatrick performed a DCF analysis of various sets of companies which he determined to have comparable risk characteristics to MDU. The results of his analyses showed that the average cost of common equity capital for those companies was then between 15.3% and 16.4% (MDU Exh. II, p. 31). Using implied dividend growth rates in his DCF model, he determined that the cost of equity for the various sets of comparable risk companies ranged from 13.20 percent to 14.92 percent (MDU Exh, II, Exh. DBF-43, p. 3 of 3). Dr. Fitzpatrick, however, stated that implied growth rates have a significant downward bias (MDU Exh. II, p. 34).

32. In his rebuttal testimony, Dr. Fitzpatrick determined that the updated cost of equity for those sets of comparable risk companies ranged between 15.00 percent and 16.54 percent (MDU Exh. JJ, Exhs. DBF-14, p. 3 of 3; DBF-16, p. 3 of 3; DBF-18, p. 3 of 3).

33. Dr. Fitzpatrick also computed a DCF cost of equity capital specifically for MDU. Using Salomon Brothers' growth projections, he calculated a consolidated MDU cost of equity of 16.91 percent. Using Value Line's growth estimates, he calculated a consolidated MDU cost of

equity of 17.91 percent. Using implied dividend growth rates, Dr. Fitzpatrick calculated a consolidated MDU cost of equity of 16.52 percent (MDU Exh. II, Sch. DBF-37, p. 3 of 3; Sch. DBF-39, p. 3 of 3; Sch. DBF-41, p. 3 of 3; Sch. DBF-43, p. 3 of 3).

34. Dr. Fitzpatrick concluded that his DCF analysis indicates that the cost of common equity capital for MDU's consolidated operations is between 16.5 and 17.9 percent. He also stated that the DCF returns for MDU's electric utility operations are between 15.3 and 16.4 percent (MDU Exh. II, p. 35).

35. In his rebuttal testimony, Dr. Fitzpatrick determined that MDU's updated DCF equity returns ranged between 15.51 and 18.01 percent, based on updated yield data and growth projections of Value Line, Solomon Brothers, and Merrill Lynch (MDU Exh. JJ, Exhs. DBF-14, p. 3 of 3; DBF-16, p. 3 of 3; DBF-18, p. 3 of 3).

36. In his original testimony, Dr. Fitzpatrick summarized that the results of his three studies fully supported MDU's requested return on common equity capital of 15.5% (MDU Exh. II, p. 35). In his rebuttal testimony, Fitzpatrick summarized the results of updating his studies and determined that as of January, 1984, MDU's cost of common equity capital was between 15% and 18% (MDU Exh. JJ, p. 4).

MCC

37. MCC witness Dr. Caroline Smith used a discounted cash flow (DCF) model to determine MDU's return on common equity. The DCF analysis yielded a range of return on equity of 12.5 to 13.0 percent (MCC Exh. 3A, p . 5) . Dr. Smith adopted her testimony in MDU gas Docket No. 83.8.58 in this proceeding. In that gas testimony, Dr. Smith included a comparable earnings study which examined the reasonableness of her DCF approach. Because she determined that the common equity cost rates for MDU's electric and gas operations are essentially the same, Dr. Smith recommended that the Commission allow a 13.0 percent common equity return. (MCC Exh. 3A, pp. 5,7)

38. Concerning the dividend yield portion of the DCF model, Dr. Smith calculated dividend yields for 95 electric and combination electric and gas utilities traded on the New York

Stock Exchange on an average price basis for the six months from April through September, 1983. The average dividend yield for the 95 companies was 10.48 percent. (MCC Exh. 1 of Docket No. 83.8.58, Appendix B, p. 2)

39. Expected dividend growth was calculated by examining growth rates in dividends, earnings, and book value over a ten year period for the companies in the study. The weighted average of all growth rates utilized in the study of these companies was 3.69 percent during that time period. (MCC Exh. 1 of Docket No. 83.8.58, Appendix B, pp. 4,8)

40. Dr. Smith used her DCF model to show the relationship between the cost of equity for the Applicant and the industry as a whole. She used the DCF statistical analysis to estimate MDU's cost of common equity capital. (MCC Exh. 1 of Docket No. 83.8.58, p. 8)

41. In explaining her recommendation of 12.5 to 13.0 percent return on common equity, Dr. Smith summarized that the Company's dividend yield was 9.2 percent, based upon market prices over the six-month period ended September 30, 1983, and the indicated dividend rate at the end of September (MCC Exh. 1 of Docket No. 83.8.58, pp. 16-17). Her estimate of the long-term dividend growth investors anticipate for MDU is in the range of 3.25 to 3.75 percent, which reflects an expectation that MDU will continue to have high growth relative to the industry, but not to the same degree that was true in the past (MCC Exh. 1 of Docket No. 83.8.58, pp. 27-28).

42. As a test of reasonableness for her DCF analysis, Dr. Smith performed a comparable earnings study. In this study, she "examined the rate of return earned on common equity in recent years by regulated electric and combination utility companies as well as returns earned by firms in the unregulated sector of the economy" (MCC, Exh. 1 of Docket No. 83.8.58, p. 29). Dr. Smith concluded that the return on common equity for all industries (regulated and unregulated) was 11 percent during 1982, while earnings in the utility industry have been in the 11 to 13 percent range over the 1972-81 period (MCC Exh. 1 of Docket No. 83.8.58, p. 34).

43. Both MDU and MCC used a DCF model to determine the cost of equity in this proceeding. The Commission has consistently preferred the DCF approach to determining cost of equity to other models based on its widespread acceptance as the most objective and accurate means of measuring investor expectations. In each DCF model in this case there are elements which are

based upon the judgment of the particular witness. Dr. Fitzpatrick performed a DCF analysis of 4 sets of comparable companies, and Dr. Smith evaluated 95 companies in her model. This Commission has consistently preferred the process of evaluating many companies in the DCF model so that factors which are unique and unusual to a particular firm can be eliminated or disregarded as being atypical utility conditions. In determining the growth portion of the DCF equation, Dr. Fitzpatrick placed more weight on the Value Line and Salomon Brothers projected dividend growth rates than on the implied dividend growth rates (MDU Exh. II, pp. 33-35). In his rebuttal testimony, he expanded his DCF analysis to include Merrill Lynch as a data source of projected growth rates (MDU Exh. JJ, p. 5). The Commission historically has downplayed the significance of such subjective projections because they are difficult to test. Fitzpatrick analyzed the accuracy of Value Line's dividend growth rate projections compared to actual dividend growth rates achieved by various electric utility companies. He concluded that Value Line's growth forecasts have been extremely accurate over the 1977-1983 period with an average of 5.63 percent projected growth compared to an average of 5.57 percent actual growth (MDU Exh. II, pp. 33-34). Dr. Smith of MCC disagreed with Fitzpatrick's conclusion based on what she perceived as two errors in his comparison: (1) his data sources have conflicts in matching of time periods; and (2) he focused exclusively on dividend growth in his comparisons while neglecting book value and earnings growth (MCC Exh. 1 of Docket No. 83.8.58, pp . 36-38) . In his rebuttal testimony, Dr. Fitzpatrick presented evidence to address the concerns of Dr. Smith. The Commission agrees that some of Dr. Fitzpatrick's data indicates that Value Line's projections of short-term growth have proven to be relatively accurate. The data also shows, however, that the growth projections have been totally inaccurate in some instances. Overall, therefore, the Commission finds the MCC approach to DCF analysis preferable to that of the Company in this proceeding.

44. In determining MDU's cost of common equity, the Commission concentrated on Dr. Smith's Appendix B, Tables B-7, B-8, and B-9 of MCC Exh. 1 in Docket No. 83.8.58. The Commission chose to disregard Smith's Table B-6 in calculating the proper return because this table represents an extreme low based on a single growth factor. Dr. Smith's Tables B-7 and B-8 incorporate MDU's two most important growth rates and all growth rates based on the calculations

of Table B-2. Tables B-7 and B-8 also incorporate industry yield and growth figures, MDU-specific yield and growth figures, and an MDU risk factor. MDU's risk factor was an area of contention in this case. The Company contended that Dr. Smith's comparison of MDU risk to that of the industry during recent MDU cases has fluctuated wildly even though the utility industry is generally stable. Under cross-examination, Dr. Smith responded:

> Well, you're making an assumption that all risk relationships stay constant. I'm not willing to join you in that assumption.
>
> The way I go about my analysis is to estimate what the cost of common equity is for the industry versus the Company, and, on the basis of that, I draw conclusions about relative risk. This is quite different from the armchair kind of analysis where we might speculate that MDU were more or less risky and then draw conclusions about the cost of equity on that basis.
>
> ***
>
> And that's what I say in my testimony. I say that because that's what the results of my analysis tell me. But I don't think it would be reasonable for you to think that MDU would always be more risky than the industry or less risky than the industry. Both the risk of MDU and the risk of the industry change all the time, particularly in the past, say, six or eight months with the problems that we've had with nuclear power in the electric industry. That's made for big shifts in risk. MDU has been fortunate to not have the problem of increased risk related to this nuclear-power construction problem. (TR, pp. 317-319)

45. The Commission agrees with Dr. Smith's analysis of MDU versus industry risk. Because of the nature of the utility industry, it should have a relatively stable risk factor over the long-run. However, short-term fluctuations for the industry as a whole seem quite logical because, for example, it is a capital intensive industry which has experienced some recent financial problems relating to construction programs, especially nuclear power plants. With that concept in mind, Dr. Smith's risk analysis appears accurate in that MDU's unique characteristics should cause to some degree differentiation in the Company's position of being more or less risky than the utility industry. Evidence of MDU's current position of being less risky than the industry as a whole is apparent: (1)

In 1982, MDU, on a consolidated basis, had perhaps the highest equity return in the industry of over 17 percent (TR, p. 302); (2) MDU has a more than adequate supply of natural gas; (3) MDU has no current major construction project in process; and (9) MDU has experienced no nuclear power construction financial problems. The Commission, therefore, finds Dr. Smith's risk analysis in this proceeding to be an accurate representation of MDU's risk in relation to that of the utility industry as a whole.

46. Concerning dividend yield, since the approved capital structure has been updated through September 30, 1983, a proper matching occurs by using a six month average of dividend yields for the period ended September 30, 1983. The Commission, therefore, determines Dr. Smith's proposed average MDU dividend yield of 9. 2 percent to be proper in this proceeding. The results of Tables B-7 and B-8, 12.1 percent and 14.6 percent, represent to the Commission the acceptable range of reasonableness for determining MDU's cost of equity. The two most important growth rates -- three-year book value growth, and seven-year earnings growth -- taken together explain a large percentage of the variability in dividend yields based on the data on Table B-2 (MCC Exh. 1 of Docket No. 83.8.58, Appendix B, p . 9) . The Commission supports the use of the two most important growth rates in the calculation of cost of equity capital because of the strong statistical correlation of the two growth rates to dividend yields. The two most important growth rates, therefore, represent to the Commission a very reasonable low end of the growth range in determining MDU's cost of equity. Incorporating all growth rates over a ten year period serves to give an overall view of MDU's cost of equity in relation to the industry as a whole over a large enough time period to show definite tendencies. The Commission believes that the all growth rates analysis results in a very reasonable high end of the growth range in determining MDU's cost of equity. The Commission also believes that utilizing 12.1 percent and 14.6 percent offers a reasonable approach to meld together industry and Company figures on a weighted basis. The Commission, therefore, determines, the averaging of the results of Dr. Smith's Tables B-7 and B-8 to be proper in this proceeding to determine MDU's cost of equity. The resulting approved cost of common equity in this proceeding is 13.35 percent (9.2 + [(2.9 + 5.4) - 2] = 13.35).

47. The approved equity return of 13.35 percent is identical to the approved equity return in MDU gas Docket No. &3 .8.58. Dr. Smith of MCC testified that, for the purpose of most industry designations, MDU is considered an electric utility, and that one of her studies "does indicate that the common equity cost rates for the Company's electric and gas operations are essentially the same" (MCC Exh. 3A, p. 7). Further support of approving identical equity returns in these two Dockets lies in the fact that MDU requested 15.5 percent for both cases, indicating similar return requirements for each segment of MDU's utility operations.

48. On page four of his pre-filed rebuttal testimony, Mr. Ian B. Davidson stated, "The consensus is that MDU's dividends will continue to grow at least in the 8-10 percent range."The Commission concedes that such growth is perhaps feasible in the short-run, but maintaining such a level in the long-run seems unrealistic, especially considering MCC's cross-examination of Mr. Davidson concerning earned return five years in the future while experiencing high levels of compound growth (TR, pp. 212-215) Dr. Smith provided a detailed description of the relationship between yields and growths:

> Long-run growth in dividends requires growth in earnings per share, which in turn, depends upon growth in book value. Because of this relationship, the historical growth patterns in earnings and book value are also important determinants of future growth in dividends. Investors apparently recognize this, as is evidenced by the high correlation coefficients between recent yields and longer term earnings and book value growth rates. (MCC Exh. 1 of Docket No. 83.8.58, Appendix B, p. 6)

The Commission finds Dr. Smith's analysis of the relationship between dividend yields and growth to be a proper approach in showing the importance of the long-run as opposed to concentrating on short-term trends. The approved equity cost level of 13.35 percent also compares very well with the industry average of 13.15 percent, calculated on Dr. Smith's Table B-5 by averaging the two most important growth rates and the all growth rates. This comparison illustrates the fact that MDU has been slightly outperforming the industry.

Rate of Return

49. Based on the findings for long-term debt, preferred stock, and common equity in this proceeding, the following capital structure and costs resulting in a 10.45 percent overall rate of return are determined appropriate:

Description	Amount (000)	Ratio	Cost	Weighted Cost
Long-Term Debt	$111,459	49.21%	8.75%	4.31%
Preferred Stock	31,823	14.05	8.79	1.24
Common Equity	83,202	36.74	13.35	4.90
Total	$226,484	100.00%		10.45%

PART C

RATE BASE

50. Consistent with previous Commission decisions, both MDU and MCC proposed a 1982 average rate base, adjusted to include certain known and measurable changes. One of the primary considerations of the Commission in rate base decisions has always been proper matching of test year income with the plant that produced that income. The Commission, therefore, finds a 1982 average rate base, adjusted for certain known and measurable changes, to be appropriate in this proceeding.

51. Prior to the first witness coming to the stand during the hearing in this proceeding, MDU and MCC stipulated into evidence in this proceeding various testimonies from witnesses heard during the MDU gas hearing in Docket No. 83.8.58. One of those witnesses whose testimony and exhibits were stipulated into the record was MCC witness Mr. Al Clark (T R, pp. 23-24). The Commission finds this procedure to be proper in this proceeding and will refer to various segments of the cross-examination of Mr. Clark in Docket No. 83.8.58 throughout Parts C and D of this Order.

Plant Additions

52. The Company proposed to include nonrevenue-producing major plant additions and retirements that were scheduled to be completed on or before December 31, 1983, which is 12 months after the end of the test year. Mr. Donald R. Ball of MDU testified, "These plant additions relate to the production, transmission, distribution and general plant functions, and are nonrevenue producing additions" (MDU Exh. TT, pp. 11-12). He also stated that these additions are necessary to meet existing consumer requirements and for replacement of existing facilities (MDU Exh. TT, p. 12).

53. MCC: witness, Mr. Albert E. Clark, proposed to exclude these post-test year plant additions from the rate base. Mr. Clark believed that inclusion of these additions would create an improper mismatch between operating income and the rate base that produced that income (MCC Exh. 4A, pp. 7-9). Clark also addressed the nonrevenue-producing standard:

> If the Commission is interested in post-test year plant additions, the standard should be "nonincome-producing" not "nonrevenue-producing." The distinction, of course, is that many plant additions are planned to provide increased operating efficiency and/or decreased operating expenses and, therefore, while an addition may not produce increased revenues, it may produce decreased expenses and an increase in the Company's net operating income. (MCC Exh. 4A, p. 8)

Specifically, Mr. Clark said that $783,915 of the $1,551,668 of MDU's proposed post-test year plant additions to rate base are directly related to the Coyote generating station and appear to be aimed at reducing operating expenses or improving operating efficiencies at that station. He stated, "To include the plant in rate base and to disregard the operating efficiencies and potential income production of these additions creates a mismatch in the test year that this Commission should not permit" (MCC Exh. 4A, pp. 8-9).

54. In rebuttal, Mr. Ball of MDU claimed that exclusion of the plant additions "compounds the problem of regulatory lag and attrition" (MDU Exh. UU, p. 1). Mr. Ball also stressed that the Company made no claim for increased operating costs for the new or additional facilities, but only requested a return on the plant additions (MDU Exh. UU, p. 2).

55. During cross-examination by Mr. Nelson of the Commission, Mr. Clark addressed the question of attrition in relation to the exclusion of posttest year plant additions:

> Q. Why would the Company not experience attrition as a result of not allowing non-revenue-producing plant additions in the rate base?
>
> A. Well, I think we have to -- I have to drop down to that bottom line and look at non-income producing. I see a mismatch created if you include post-test-year plant additions that have a potential to either increase revenues or to decrease-expenses. By eliminating that mismatch, I don't see where you create attrition.
>
> (TR of Docket No. 83.8.58, pp. 424-425)

56. The Commission believes that Mr. Clark's above argument is crucial in maintaining the integrity of the historical test year concept. Matching must occur between operating income and the rate base that produced that income. When such a matching is properly realized, the Company is given fair treatment and attrition is minimized. Inclusion of additional plant without reflecting associated revenue and expense adjustments renders useless the computation of rate of return earned before any allowed revenue increase. Allowing a return and depreciation expense recovery on a plant addition without also reflecting, for example, decreased operating expenses resulting from more efficient operation results in a windfall to the Company and an excessive expense to the consumer. The Commission endorses the historical test year concept and, therefore, believes that the inclusion in rate base of post-test year plant additions without commensurately including the net operating income effects of such inclusion results in a mismatch which is unacceptable. The Commission, therefore, finds the rate base reduction proposed by MCC concerning post-test year plant additions in the amount of $633,967 to be proper in this proceeding.

Materials and Supplies

57. MCC proposed to increase materials and supplies by $1,815. Mr. Clark testified, "When the Company made its adjustment to convert beginning and end of test year average to the average of thirteen month-end balances for the test year, different shrinkage ratios were used" (MCC

Exh. 4A, p. 9). Clark proposed to use the same shrinkage ratio for the 13-month average balance as MDU used for its beginning and ending average calculation (MCC Exh . 4A, p . 9).

58. The Company did not rebut Clark's proposal, and the Commission believes that the shrinkage ratio should be the same for the two average balance calculations. The Commission, therefore, finds an increase in the materials and supplies portion of rate base in the amount of $1,815 to be proper in this proceeding.

Unamortized Gain

59. Mr. Clark of MCC proposed to reduce the Company's pro forma rate base by the unamortized gain on reacquired debt. Clark referred to Interim Order No. 5020 in this Docket and Order No. 4918b of Docket No. 82.6.40 in defense of his adjustment in the amount of $267,344 (MCC Exh . 4A, p . 10).

60. Mr. John F. Renner of MDU countered MCC's proposed adjustment in his rebuttal testimony. Mr. Renner stated that in the case of unamortized gain on reacquired debt, "the Company must expend funds without regard to the source of those funds in order to realize that unamortized gain" (MDU Exh. HH, p. 2). Renner maintained that MCC's proposal would result in a double credit to ratepayers, "first by deducting the unamortized gain from rate base and then again reducing interest expense for amortization of that gain " (MDU Exh. HH, p . 2).

61. The Commission disagrees with the reasoning of Mr. Renner. As discussed in the Cost of Capital section of this order, the Company and MCC agree that interest expense should be reduced for amortization of the gain from reacquired debt. The remaining question is what proper treatment should be given to the unamortized balance of the gain from reacquired debt. In past cases, the Commission has treated deferred taxes as a rate base reduction because it is a deferred credit and has no return requirement. Unamortized gain is also a deferred credit. The Commission finds that because of the reacquisition of the debt at a discount, a cash savings to MDU results which is accounted for as a gain. By deducting the unamortized portion of the gain from rate base, the Commission is precluding the Company from earning a return on the unamortized balance of the gain, and, therefore, allowing the consumers to realize full benefit from the transaction. The

Commission finds that the unamortized gain is a deferred credit, similar to deferred taxes, for ratemaking purposes. The Commission determines, there fore, that the unamortized gain on reacquired debt should be treated as an allocated deduction from rate base in the amount of $252, 994 using the approved allocation factors.

Oil Stocks

62. MCC witness Clark proposed to reduce the level of oil stocks at the Company's Ellendale, Mobridge, and Glendive stations and to eliminate the oil stocks at the Miles City and Williston plants (MCC Exh. 4A, pp. 10-11). Because the Ellendale, Mobridge, and Glendive plants did burn oil during the test year, although none in excess of 100 operation hours or at full load operation, Mr. Clark proposed to reduce their oil stocks to MDU's stated policy level of 100 hours of full load operation. The Company is proposing to include in rate base nearly six years of oil supply. In addition, MDU has requested oil stocks for the Miles City and Williston plants. Because neither of these plants has burned oil since 1980, Mr. Clark proposed to eliminate the oil stocks related to these two units on the basis that the oil does not provide any service to ratepayers. Mr. Clark's total proposed oil stock reduction is $326, 599 . (MCC Exh. 4A, p. 11)

63. Mr. W. W. Kroeber of MDU disagreed with the proposed adjustments of Mr. Clark to reduce to zero the oil stocks at the Miles City and Williston power plants. Because of the possibility of gas supply interruptions for firm customers, Mr. Kroeber stated, "It is imperative from an operational standpoint that MDU maintain a supply of oil at both the Miles City and Williston power plants in order to achieve the necessary reliability for these plants and assure they are available to us when we need the capacity to serve our customers" (MDU Exh. SS, p. 6). MDU did not rebut Mr. Clark's proposal to reduce the oil stocks at the Ellendale, Mobridge, and Glendive plants to the Company's stated policy level of 100 hours of full load operation.

64. The Commission shares MCC's concern about the level of oil stocks at these various plants. The operation records clearly indicate that all of these plants in question have been burning considerably less oil than the MDU proposed levels of oil stocks would seem to support. Concerning the Ellendale, Mobridge, and Glendive plants, allowing an oil stock that provides for 100 hours of

generation at the maximum nameplate rating seems very generous to the Commission, especially considering the limited operation of the plants in recent years. The Commission, therefore, in accordance with MDU's stated policy for oil stock levels of 100 hours of full load operation, finds MCC's proposed reduction of oil stocks for the Ellendale, Mobridge, and Glendive plants, in the amount of $220,013, to be proper in this proceeding.

65. Concerning MCC's proposal of elimination of oil stocks at MDU's Miles City and Williston plants, the Commission agrees with MCC that the records indicate the propriety of a more drastic adjustment than that discussed in the above Finding of Fact paragraph No. 64. Since neither plant has burned oil since 1980, a very limited oil stock at these plants is totally reasonable. Keeping in mind the importance of the availability of these plants, the Commission finds the oil stock level of 24 hours to be reasonable for these two plants in this proceeding. The resulting rate base reduction is in the amount of $86,965, based on data from page 7 of Mr. Kroeber's rebuttal testimony and Schedule 3, page 4 of 6, of Mr. Clark's testimony. The Commission, therefore, determines the total amount of rate base reduction associated with MDU's oil stocks in the amount of $306,978 to be proper in this proceeding.

66. In making this oil stock adjustment, the Commission would like also to comment on the high price level of all the volumes of oil stock. Allowing such expensive old oil in rate base is bothersome to the Commission and seems to reflect an unconcerned attitude on the part of MDU in its stated policy efforts of keeping costs at a minimum for the benefit of its customers.

<u>Coyote Plant</u>

67. In Docket No. 81.1.2, the Commission disallowed 30 megawatts (MW) of Coyote plant capacity from cost of service. In this proceeding, the Company proposed to reflect 100 percent of its ownership of the Coyote: generating station in cost of service. MCC witness Clark agreed that it is appropriate to reflect 100 percent of MDU's interest in the Coyote plant in cost of service, but he did not agree with all of the Company's proposals in this matter . (MCC Exh. 4A, p. 12)

68. In making his recommendation of inclusion of the 30 MW of Coyote capacity, Mr. Clark covered four points of analysis. Firstly, MDU's capacity would have been deficient during July and August of 1983 without the 30 MW of Coyote capacity at issue in this proceeding. Secondly,

Clark characterized the MDU electric system as bi-modal, having both a strong winter and summer peak. Mr. Clark stated that even though MDU peaks in the winter, the summer period is the critical capacity time for the Company. Thirdly, Mr. Clark stated that it is unreasonable to expect a utility never to have excess generating capacity on its system since generating capacity typically cannot be economically installed in slices sufficiently small to coincide precisely with customer demands. Lastly, Mr. Clark looked at the Company's projections of load growth for the period 1984-1986 and determined that the facility is and will be used and useful for electric service on MDU's system. (MCC Exh. ,4A, pp. 13-15)

69. During the various "satellite" hearings in this Docket, many public witnesses expressed strong views that the Coyote plant should not be completely included in the rate base. The Commission appreciates the public's willingness to express their opinions concerning this matter and considered these testimonies in determining proper treatment for this plant. In analyzing the record, however, the Commission found the load data presented by MCC and MDU to be persuasive. The load data indicates that all of the Coyote plant is and will be used and useful. The Commission, therefore, finds the inclusion of 100 percent of the Coyote plant in MDU's cost of service to be proper in this proceeding.

70. In including the previously disallowed portion of Coyote in the rate base, the Commission emphasizes that this determination is based on the evidence in this record, but is not necessarily an endorsement of the parties' positions in this case. Mr. Clark, as did MDU, based his recommendation on the analysis of MDU's summer and winter peaks, rather than on an annual energy basis. In the future, the Commission will analyze MDU's load data from both perspectives in evaluating new plant additions.

71. As stated earlier, Mr. Clark did not agree with all of the Company's adjustments to reflect the total Coyote plant in MDU's cost of service. Clark proposed two sets of adjustments, each set being comprised of two parts. Firstly, he proposed an adjustment to match the accumulated provision for depreciation and the unamortized deferred depreciation expense. Secondly, he proposed an adjustment to the accumulated AFUDC to be included in the pro forma rate base. (MCC Exh. 4A, p. 16)

72. Concerning the first set of adjustments, Mr. Clark testified:

> For book purposes, the Company deferred the depreciation expense related to the Montana portion of the disallowed Coyote investment. However, a credit was entered to the accumulated provision for depreciation. Since this portion of the plant was not in the Montana rate base, the accumulated provision for depreciation and the unamortized deferred depreciation expense should exactly offset one another so that the net impact on rate base is the gross plant that was originally excluded (ignoring additional AFUDC). (MCC Exh. 4A, p. 17)

Clark explained that MDU has included $510,506 in the accumulated provision for depreciation, a rate base reduction, and has included $819,189 for unamortized deferred depreciation expense, a rate base increase- (MCC Exh. 4A, p. 17). The difference between the two figures, which Clark believes should be exactly the same, is $308,683.

73. As a result, Mr. Clark stated that MDU's proposed rate base is overstated by $308,683 because of a mismatch in the time frames used by the Company to calculate these two adjustments. Clark said that the effect of the Company's mismatch would be to provide for the return of more capital to the investors than the investors supplied. He noted that the time frame for this adjustment does not affect his recommended adjustment. To be consistent with his second set of adjustments, which will be discussed below, Clark adjusted both balances in question to June 30, 1983. He said that, for this adjustment, it does not matter what time period is used or whether an average or some point in time is used, and that what is necessary is that the time frame- is the same for both balances so that the two amounts offset each other and the rate base includes only the gross plant originally disallowed. The resulting proposed adjustment is a rate base reduction in the amount of $308,683. (MCC Exh. 4A, pp. 17-18)

74. Mr. Ball of MDU disagreed with Mr. Clark's proposed first set of adjustments and said that Clark's argument only makes sense if one views the determination of the total rate base level in a vacuum (MDU Exh. UU, p. 2). Ball stated that in all likelihood it will be mid-1984 before any final rates are effective as a result of this proceeding and that even the Company's proposed rate base in this proceeding will not be totally reflective of the Company's investment in facilities at the time the final rates become effective. He further argued, "If Mr. Clark's suggestions are followed,

the rate base level will be even less reflective of MDU's investment, thus limiting MDU's opportunity to earn its allowed return" (MDU Exh. UU, p. 2).

75. The Commission understands MDU's concerns about regulatory lag and attrition, but these problems do not appear to exist in terms of the proper handling of these proposed adjustments. Regardless of MDU's investment level at the time the rates from this proceeding will become effective, proper matching within the confines of the rules governing the use of an historical test year must be observed. There should be, therefore, a matching between the accumulated provision for depreciation and the unamortized deferred depreciation expense as they should offset each other. As will be discussed below, the Commission does not accept MCC's balance date of June 30, 1983, but, as Mr. Clark pointed out, it does not matter what time period is used or whether an average or some point in time is used in calculating the proper adjustment. The Commission, therefore, finds the matching of the balances at December 31, 1983, resulting in a rate base reduction of $308,683 to be proper in this proceeding.

76. Mr. Clark's second set of proposed adjustments to rate base for the previously disallowed portion of Coyote plant reduced the amount of AFUDC included in the rate base. The first component of this adjustment reduced the AFUDC rate to the overall rate of return of 10.23 percent allowed in Order No. 4799b of Docket No. 81.1.2. Secondly, Clark proposed to stop the accrual of AFUDC at June 30, 1983. (MCC Exh. 4A, p. 19)

77. Concerning reducing the AFUDC rate to 10.23 percent, Mr. Clark disagreed with the inclusion of short-term debt in the calculation of the AFUDC rate because the Coyote plant was not under construction, but rather, was a completed facility, part of which was deemed to be not used and useful and, therefore, not allowed in rale base. He testified, "Therefore, we are not dealing with the cost of funds necessary to construct this facility, but the cost of funds for not including the facility in rate base" (MCC Exh. 4A, p. 20). Clark, as a result, proposed the AFUDC rate of 10.23 percent, which is the overall rate of return allowed by the Commission in MDU's last Montana electric rate case, Docket No. 81.1.2.

78. Mr. Ball of MDU rebutted Mr. Clark's AFUDC rate proposal. Ball referred to the last Commission Order in Docket No. 81.1.2 where the Company was ordered to continue to accrue

AFUDC on the portion of the Coyote plant not allowed in rate base in that proceeding. He said that MDU closely followed the instructions of the Federal Energy Regulatory Commission (FERC) in accruing AFUDC and that using any AFUDC rate other than a rate determined in accordance with such regulations is totally illogical and in violation of this Commission's Order in Docket No. 81.1.2. (MDU Exh. UU, p . 3) Ball stated, "Mr. Clark now proposes to deny recovery of amounts previously recorded on the Company's books in compliance with the previous order of this Commission" (MDU Exh. UU, p. 3).

79. The Commission basically agrees with the logic of MCC witness Clark, in that short-term debt probably should not have been included in the AFUDC rate for the disallowed portion of the Coyote plant, which was a completed unit not requiring short-term debt financing, rather than one under construction. To change the rate of AFUDC accrual at this point in time, however, would be unfair to MDU especially since MDU has merely complied with the Commission's Order in Docket No. 81.1.2. The Commission believes that the proper time to re-evaluate the allowed AFUDC rate for the disallowed portion of the Coyote plant was in the form of a Motion For Reconsideration immediately after the release of the Commission Order in Docket No. 81.1.2. At that time, any proper adjustments to the accrual rate could easily have been implemented. The Commission also believes that a learning curve exists in the handling of new power plants as utilities propose to bring them into their cost of service, especially when all or part of such a plant is determined by the Commission to be not used and useful and is, therefore, not allowed into the rate base. This Commission has gained much more experience and knowledge on the subject of disallowed portions of power plants since the Coyote decision in question, which was made in the latter part of 1981. Hindsight provides the ability to scrutinize previous decisions, and typically, some prove to be better than others. Having considered all these factors, the Commission, therefore, finds the rate of AFUDC accrual of the previously disallowed portion of the Coyote plant, in proper accordance with the FERC AFUDC instructions, to be proper in this proceeding. MCC's proposal of using 10.23 percent as the AFUDC rate is, therefore, denied.

80. Concerning the second portion of the second set of MCC witness Clark's proposed adjustments, he proposed that the accrual of AFUDC be stopped at June 30, 1983. He believes that

MDU's filing in this proceeding was tardy and should have been filed in time to have rates in effect that reflected total Coyote by June 30, 1983. He testified, "The Company's projections of its load and capacity position for the summer of 1983 should have precipitated a rate case approximately one full year earlier than when this case was filed" (MCC Exh. 4A, p. 20). He, therefore, felt that the Company should have been more responsive to its own projections. Clark continued:

> Also it is important to remember that the basis of the 30-MW exclusion was the Company's own projections for a period of time two years after the close of the test year in Docket No. 81.1.2. Using this same two-year horizon would require a 1981 test year and a filing in 1982. (MCC Exh. 4A, p. 21)

81. In defense of the Company's request that AFUDC be accrued through June 30, 1984, Mr. Ball of MDU rebutted MCC's proposal:

> Mr. Clark is extremely presumptuous in substituting his judgment for that of MDU's management with respect to the timing of rate case filings and also in substituting his judgment for that of this Commission with respect to his assumed approval by this Commission of -the full value of the Coyote plant one full year earlier than proposed in this case. Acceptance of this ridiculous proposal would forever deny recovery of amounts already recorded on MDU's books pursuant to a previous Commission Order and would also conflict with the very basis upon which this Commission allowed interim rates only a few months ago. (MDU Exh. UU, p. 5)

Mr. Ball explained that the approved interim rates in this proceeding do not reflect the inclusion of the disallowed portion of the Coyote plant. Ball also discussed the fact that MDU's electric consumers were spared the effects of a rate increase that Mr. Clark contends should have occurred by June 30, 1983, to reflect all of the Coyote plant. (MDU Exh. UU, p. 5)

82. The Commission believes that the filing by a utility for a rate increase is, within reason and the confines of related statutes, a management decision. Perhaps MDU really should have filed an electric rate case in 1982 asking that all of Coyote be reflected in rates, but the fact that the Company did not do so should not preclude MDU from eventually realizing the AFUDC which it has been properly accruing as directed by the Commission in Docket No. 81.1.2. The Commission also recognizes the savings that Montana MDU electric customers have realized by the Company's

decision not to file for an electric increase in 1982. The Commission, therefore, rejects MCC's proposal to stop the AFUDC accrual at June 30, 1983, and finds it proper for MDU to continue accruing AFUDC until this Final Order is approved. The Commission also, however, finds that in this proceeding MDU is allowed to recover AFUDC accrued through December 31, 1983, 12 months beyond the end of the test period, rather than through June 30, 1984, as proposed by MDU. Since MDU is allowed to continue accruing AFUDC until this Final Order is approved, the residual accrued AFUDC (between January 1, 1984 and the approval date of this Final Order) will have to be handled as an item in a subsequent rate filing. The Commission, therefore, finds a rate base reduction in the amount of $880,185 to reflect the inclusion in rate base of accrued Coyote AFUDC up through December 31, 1983, to be proper in this proceeding.

83. The above adjustment of $880,185 takes into consideration that in his rebuttal testimony, Mr. Ball stated that MDU discovered a minor computational error in the calculation of the AFUDC rate and that the AFUDC rate used to estimate the accrual through June of 1984 has actually decreased. The adjustment of $880,185, therefore, reflects the proper level of accrued AFUDC at December 31, 1983.

84. The total amount of Coyote-related rate base adjustments found to be proper in this proceeding is, therefore, a reduction in the amount of $1,188,868 (308,683 + 880,185 = 1,188,868).

Total Rate Base

85. As a result of the approved adjustments described above, the Commission finds the proper amount of total 1982 average rate base, adjusted for known and measurable changes, to be $67,984,829 in this proceeding.

PART D

REVENUES, EXPENSES, AND REVENUE REQUIREMENT

86. Mr. Donald Ball of MDU sponsored exhibits and testimony which detailed the cost of service and average rate base amounts which support the revenue increase request of $8,731,439. The request was based on an overall rate of return of 11.386 percent. Mr. Ball indicated that the

Company utilized a 1982 historical test period as a basis for its filing and made various 1983 adjustments. Mr. Ball concluded that, based on the test period ending December 31, 1982, the Company would require additional revenues of $8,731,439 in order to earn an overall return of 11.386 percent (MDU Exh. TT, p. 5).

87. Mr. Albert E. Clark, expert witness for MCC, presented testimony and exhibits on the cost of service and the proper rate base. Mr. Clark urged the use of an average 1982 rate base, as was also proposed by the Company, adjusted for certain known and measurable changes. He prepared a series of schedules and presented related testimony which culminates with the change in revenues required to produce the 10.33 percent rate of return recommended by Dr. Caroline Smith. Mr. Clark concluded that, based on the 1982 average test year, the Company requires additional permanent revenues of $4,836,927.

Operating Revenues

88. In its filing, MDU proposed one adjustment to revenues which decreased revenues by $19,192 to reflect the full annual effect of the time-of-day rate (Rate 30) which became effective January 1, 1983, for Shell Oil Company and the current residential rate. The net effect of the above adjustment to operating revenues results in pro forma revenues of $24,905,848. (MDU Exh. TT, p. 6; Exh. DRB-5, p. 1 of 2)

89. Mr. Clark of MCC proposed no further adjustments to the Company's pro forma revenue figure of $24,905,848.

Plant Additions

90. Mr. Clark of MCC proposed to eliminate the depreciation expense and taxes related to the post-test year plant additions proposed by MDU to be included in rate base. Because he had eliminated these post-test year plant additions from rate base, Mr. Clark believed it would be proper to remove the expense items related to the removal of the plant additions (MCC Exh. 4A, p. 22).

91. In the rate base section of this Order, Finding of Fact Nos. 52 through 56, the Commission discussed whether or not to include the post-test year plant additions in rate base and determined that these plant additions should not be included in rate base. Such exclusion from rate

base of these plant additions necessitates the elimination of related expenses to achieve proper matching. The Commission, therefore, finds the MCC proposed adjustments to depreciation expense and taxes, related to the elimination of post-test year plant additions from rate base, resulting in a net decrease of operating expenses in the amount of $23,365 to be proper in this proceeding.

Rate Case Expense

92. The Company requested inclusion in rate case expense of an estimated $175,000 for this proceeding (MDU Exh. FF, St. G, p . 6 of 11).

93. Mr. Clark of MCC said that it appears that the cost incurred by MDU for Docket No. 81.1.2 was the determining factor in the Company's decision to request $175,000 for this case. He continued, "However, because of the additional costs incurred in that docket for the Phase II (rate design) and the litigation of the "used and useful " issue as it related to the Company's excess capacity, I do not believe that Docket No. 81.1.2 can be considered a typical rate case for setting rates prospectively" (MCC Exh. 4A, p. 32). Mr. Clark proposed to use $100,000 for the estimate of rate case expense for this Docket, based on the use of the Company's original estimate of $58,000 for Docket No. 81.1.2 (MCC Exh. 4A, p. 32). He concluded, "[I]t is known that the expense will be incurred, but the amount is not measurable" (MCC Exh. 4A, pp. 32-33). Mr. Clark, therefore, proposed to reduce rate case expense by $37,500, which reflects the two-year amortization of rate case expense as proposed by MDU.

94. In rebuttal testimony, Mr. Ball of MDU discussed the procedure of accounting for and reflecting in cost of service actually incurred rate case expenses, including an estimate for the current case plus adjustments, as necessary, to reflect actual expenses for prior cases. He maintained that the Company's filing in this proceeding reflected that procedure. (MDU Exh. UU, pp . 8-9)

95. During the hearing in this proceeding, Mr. Nelson, staff attorney for the Commission, cross-examined Mr. Ball of MDU:

Q. In response to a Consumer Counsel data request, you estimated the attorneys' fees for this rate case to be 38,000.

A. I personally did not prepare that estimate.

Q. Do you agree with that estimated figure?

A. It may be a touch on the high side in view of the last actual amount that was spent (TR. p. 186)

Mr. Ball's above response indicates to the Commission that Mr. Clark is correct in assessing that MDU's estimate of rate case expense related to this Docket is likely overstated. In this proceeding, MDU filed a marginal cost study, similar to the one performed in Docket No. 81.1.2, the cost of which is included in rate case expense. Since the format of the two studies is quite similar, the cost of developing the format would probably not be present in this Docket, resulting in a lower overall cost associated with this study.

96. Having considered the above factors, the Commission determines that Mr. Clark's rate case expense estimate of $100,000 for this Docket, and the related adjustment of $37,500, are proper in this proceeding. The Commission agrees with Mr. Clark that an estimate of rate case expense for this Docket of $100,000 is-quite generous given the Company's estimate of $58,000 in Docket No. 81.1.2. In allowing this reduction of $37,500 for rate case expense, the Commission maintains its belief in the concept that rate case expense for utilities should be amortized over a period of time of at least two years. The two-year amortization approach was proposed by the Company and endorsed by MCC in this proceeding, which accounts for the reduction of $37,500 (half of $75,000) for rate case expense even though the total adjustment is $75,000.

Labor Expense

97. MDU's labor costs were annualized recognizing progression increases and general wage increases received during 1982 and through September 30, 1983. The Company's labor expense was calculated based on the average number of employees in 1982. (MDU Exh. TT, p. 7)

98. Mr. Clark of MCC proposed to reflect actual payroll expenses for the 12 months ended September 30, 1983, using average test year (1982) employees. Clark justified his proposed reduction of $34,226 by claiming that the Company's adjustment was based "to a large degree on speculation and estimates" (MCC Exh. 4A, p. 25). On page 19 of its Brief, MCC adjusts the above

number to $29,908 as a result of using average employees during the 12 month period ending September 30, 1983, rather than test year average employees.

99. In his rebuttal testimony, Mr. Ball of MDU disagreed with Mr. Clark's statement that the Company's labor expense adjustment had been based largely on speculation and estimates. Mr. Ball claimed that the labor Q" adjustment is based on known pay levels and increases pursuant to labor contracts in existence at the time the data was prepared (MDU Exh. UU, p. 6)

100. The Commission believes that the proposed approach of MCC is inadequate in that this method does not allow for the annualization of known and measurable salary and wage increases. In past cases, the Commission has allowed the annualization of post-test period contractual wage increases as a known and measurable change. The allowance of such annualization also serves to counteract attrition.

101. The Commission, however, is alarmed by the percentage increase requested by MDU to cover increased labor costs. The proposed increase of 9.6801 percent is disturbing in view of an annual inflation rate of approximately 4.5 percent. The purpose or intention of the Commission is not to attempt to override or negate contracts resulting from the collective bargaining process, but the Commission feels compelled to give MDU a strong message that labor expense percentage increases of this magnitude are indeed questionable, given the present rate of inflation, unless such increases are offset by productivity gains. The following table, MDU's response to the MCC Data Request No. 13 of October 21, 1983, in Docket No. 83.8.58, illustrates the Commission's deep concern for this rapidly growing expense item:

Request No. 13: Provide a schedule that shows total wages and salaries for 1979, 1980, 1981, 1982 actual and 1982 pro forma for each of the following:

a) Officers
b) Non-union other than officers
c) Union

Response: The requested schedule is as follows and is based on the W-2 reporting period:

Year	Officers	Non-Union	Union
1979	$636,282	$15,576,593	$12,958,785
1980	675,646	18,610,587	15,435,997

1981	673,281 1/	21,807,716	18,022,099
1982	840,938 2/	24,028,479	19,828,227
1982 pro Forma 3/	922,342	26,354,460	21,747,619

1/ Reflects reduction of one officer.
2/ Reflects addition of two officers.
3/ 1982 actuals plus 9.6801% per Rule 38.5.157, page 3 of 15.

102. The Commission realizes that some of the above large increases undoubtedly represent construction projects when the number of laborers increases significantly. At this time, however, MDU has no large construction projects, and, therefore, the overall number of employees should be stabilizing. In fact, with declining off-system gas sales, perhaps the overall work force for MDU should be declining.

103. Of the above types of MDU employees - officers, non-union other than officers, and union - the Commission most often heard concerns of consumers in public testimony during satellite hearings for this Docket and Docket No. 83.8.58 relating to the level of salaries and increases for the officers of MDU. Many consumers expressed great disappointment that the Company had not made an effort to hold executive salary levels to reflect hard economic times which have prevailed over the last couple of years, especially the 1982 test year, and asked the Commission to consider the matter closely. The Commission recognizes that the amount of officer salary increases in this case are different for ratemaking purposes than the actual figures because of allocation to electric, annualization, and the labor expense methodology in this proceeding. The Commission, however, believes that a strong message must be sent to MDU that such officer salary increases fail to reflect the severe economic conditions under which consumers have been struggling. The Commission also notes that large officer salary increases seem unwarranted considering the fact that the inflation rate has overall been in a declining state since the beginning of 1982. If stockholders are rewarding top executives for increased productivity and resulting increased profits in troubled economic times, then it seems only reasonable that just as they share in the rewards or profits, so must the owners assume a fair portion of the burden of increased officer salary levels that the stockholders deemed justified for their increased return on investment. The Commission is satisfied that the present base salary

levels are adequate to attract competent officers to work for MDU. Any officer salary increases desired by the owners should be made up from productivity gains or from the stockholders themselves. The Commission, however, also recognizes that the record in this proceeding was not well enough developed to properly reduce the officers' salaries portion of this expense. The Commission, therefore, serves notice to MDU that this issue will be fully explored in the next general electric proceeding and makes no officers' salaries adjustment in this proceeding.

104. MDU proposed to add overtime, commissions, bonuses, part-time and temporary labor, and other to the average payroll in order to determine the total labor expense. Commissions and bonuses should relate directly to productivity gains and, therefore, should not be included in the labor expense calculation. Also, the commissions related greatly to the nonelectric utility activity of appliance sales and, therefore, should not be included as a viable component in determining the percentage increase to electric utility labor expense. The component of "other" was unexplained and, therefore, cannot be included in the calculation of labor expense percentage increase because it is unidentified as relating to the gas utility. The following table shows the calculation of this portion of the labor adjustment:

Commissions	$176,383
Bonuses	44,284
Other	76,924
Total Amount Disallowed	$297,591
Electric Portion	95,850
Montana Portion	$ 24,684

105. Based on the above discussions and calculations, the Commission finds a reduction in labor expense in the amount of $24,684 to be proper in this proceeding. In making this adjustment, the Commission strongly adds that this entire issue will be examined very closely in MDU's next general electric filing.

FICA Taxes

106. The approved adjustment to labor expense results in a $2,173 reduction in FICA taxes. The Commission determines that this adjustment is appropriate since this reduction coincides with the Commission approved labor adjustment which was a reduction in the amount of $24,684.

<u>Other Taxes</u>

107. Mr. Clark of MCC proposed to reverse the Company's adjustment which provides a blanket 17 percent increase to all taxes other than income taxes except FICA and MCC taxes, based on a comparison of 1983 accruals to 1982 expenses. Clark stated that only by chance would the Company's accruals actually match the annual expense, because accruals represent an estimate of what the expense is likely to be. Clark testified that the Company did not offer any evidence that these tax expenses are going to increase at an annual rate of 17 percent, and, therefore, the adjustment should be rejected because it does not fit the Commission's known and measurable test. Finally, Mr. Clark found error with the Company's calculation in that it includes FICA and MCC taxes in both the numerator (1983 accruals) and the denominator (1982 expense), while the purpose of the adjustment is to reflect increases in taxes other than income taxes except FICA and MCC taxes. (MCC Exh. 4A, pp. 23-24)

108. The Company did not rebut Mr. Clark's proposal, and the Commission agrees that MDU's proposed adjustment does not meet the known and measurable test because of its speculative nature. The Commission, therefore, finds a reduction in other taxes in the amount of $149,001 to be proper in this proceeding.

<u>Amortization of Pre-1974 Gain</u>

109. In his proposed adjustments, Mr. Clark included an allowance for the amortization of pre-1974 profit on debt reacquired at a discount. Mr. Clark explained:

> Before 1974, MDU credited the gain on reacquired debt directly to retained earnings. Since 1974, the gains have been credited to Account 257-Unamortized Gain on Reacquired Debt. This account has been treated as a rate base deduction. But, the pre-1974 gains are not included therein. Therefore, as this Commission has previously ruled in MDU rate cases, and as ordered for the purpose of setting interim rates in this proceeding, I have credited income for the amortization of the pre-1974 gains on reacquired debt. (MCC Exh. 4A, p. 30)

110. The Company did not rebut Mr. Clark's proposal, and the Commission has consistently ruled that pre-1974 profit from reacquired debt should be flowed through over time to

consumers to reflect a benefit to those who had been paying for the cost of the debt before being reacquired. The Commission, therefore, finds the MCC adjustment in the amount of $14,000 to reflect the pre-1974 gain on reacquired debt to be proper in this proceeding.

Industrial Memberships

111. MCC witness Clark proposed to remove a portion of the dues paid by MDU to certain associations and industrial groups. Clark proposed to eliminate a majority of the associations in question, resulting in an adjustment of $6,830 (MCC Exh . 4A, p . 26) . Concerning the major association, Edison Electric Institute (EEI), Clark did not recommend to eliminate its related costs from operating expenses. He did, however, recommend "that the Commission order the Company to justify the inclusion of these costs in cost of service at its next gas rate case" (MCC Exh. 4A, p. 21).

112. The Company did not rebut Mr. Clark's proposal but did address the issue in its Brief. On page 30 of the Brief, MDU stated that such association dues "are a customary part of doing business and a normal business expense for all businesses, not just utilities. " The Company also stressed that the propriety of these expenses should be viewed in the context of the business community as a whole (MDU Brief, p. 31).

113. The stockholders of MDU apparently find the participation in such nonelectric industry organizations as Old West Trail Foundation and North Dakota Newspaper Association to be proper expenditures. The Commission, however, fails to recognize any benefit to MDU ratepayers for involvement in these nonelectric industry organizations. The Commission, therefore, finds the elimination of dues in the amount of $6, 830 as proposed by MCC to be proper in this proceeding.

114. Concerning those associations which Mr. Clark included as proper expenditures, the Commission agrees with Mr. Clark that this issue should be thoroughly examined during the next MDU general gas filing. For purposes of this proceeding, however, the Commission believes there should be a sharing of costs between stockholders and ratepayers for the association dues included in cost of service by Mr. Clark of MCC. Mr. Clark pointed out that the association for which the largest amount of dues is paid, Edison Electric Institute, sponsors advertising campaigns that could

be considered promotional or institutional in nature (MCC Exh. 4A, p. 26). The Commission accepts the Company argument that ratepayers receive some benefit from participation in these organizations, but the Commission also maintains that the stockholder receives some benefit from such membership. In determining the proper and fair sharing percentage for these clues, the Commission considered using a 50-50 percent split but decided that since the exact amount of promotional and institutional advertising of these associations could not be quantified in this proceeding, a moderate approach would be taken. The Commission, therefore, determines that a further reduction of the allowed association dues in the amount of 25 precept, or $4,698, representing a reasonable portion of stockholder benefit from participation in these organizations, is proper in this proceeding. As further indication that this problem should be further explored, the Commission notes that it has received information subsequent to the hearing concerning such organizations as Committee For Energy Awareness. Even though this information casts great doubt on the validity of such dues as a benefit to ratepayers, the Commission will make no explicit adjustment for those organizations in this proceeding.

115. Based on the above discussions of various adjustments to association dues expense, the Commission finds a reduction in dues expense in the amount of $11,528 (6,830 + 4,698 = 11,528) to be proper in this proceeding. In making this adjustment, the Commission stresses that all association dues must be fully explained, justified, and quantified in the next general electric rate filing.

Pro Forma Interest Expense

116. MCC witness Clark calculated pro forma interest expense using the same procedure used by the Company in its exhibit. The interest expense Clark calculated is somewhat higher than the Company's because he used his adjusted rate base and MCC witness Smith's weighted debt cost rather than the rate base and weighted debt cost proposed by MDU. The Commission finds that a pro forma interest adjustment is proper to reflect the tax effect of interest on construction. By utilizing the approved rate base and weighted cost of long-term debt in the methodology, the Commission

finds a decrease to Montana Corporation License Tax in the amount of $23,977 and a decrease to Federal Income Tax in the amount of $152,372 to be proper in this proceeding.

Research and Development

117. Mr. Clark of MCC proposed to eliminate the Company's requested adjustment to increase test year expenses in the amount of $10,091 for 1983 EEI costs associated with research and development. The Company's proposal reflects growth-in revenues and sales from 1980 to 1981 and was calculated by applying unit charges to the utility's revenues and kwh sales in the second preceding year. Clark said, " [T]o base an adjustment on growth without giving effect to increased future revenues is improper" (MCC Exh. 4A, p. 31).

118. In his rebuttal testimony, Mr. Ball of MDU countered Mr. Clark's proposal by saying that MDU's proposed adjustment reflects actual conditions and does not reflect the higher 1982 revenues and kwh sales upon which the test year is based (MDU Exh. UU, p. 8).

119. The Commission agrees with MCC that test year expenses should not be adjusted for increases associated with future growth in sales because such increases will be covered by an accompanying growth in future revenues. The Commission, therefore, finds a reduction of $10,091 to reflect elimination of increased EEI research and development expenses to be proper in this proceeding.

Coyote Plant

120. In accordance with his previously discussed Coyote-related rate base adjustment proposals, MCC witness Clark proposed to reduce the depreciation expense for the additional AFUDC and amortization expense for the unamortized deferred depreciation expense for the previously disallowed portion of the Coyote plant. In making these related expense adjustments, Mr. Clark accounted for his proposed changes in the AFUDC rate and the June 30, 1983, cutoff date for accruing AFUDC. He reduced the annual amortization expense to reflect the remaining life of the Coyote plant in lieu of the Company's proposed three-year amortization, and he reduced the unamortized balance to its June 30, 1983 level. (MCC Exh. 4A, p. 28)

121. In explaining his proposed adjustment to recover the unamortized deferred depreciation expense and the additional AFUDC accrued on the plant while it was not in rate base over the remaining useful life of the plant rather than over a three year period, Mr. Clark testified:

> Since this plant was originally disallowed rate base treatment because it was not used and useful to Montana's ratepayers, the effective useful life of the plant has been reduced. Therefore, there should be no distinction, for ratemaking purposes in Montana, between the unamortized deferred depreciation expense and the additional AFUDC accrued on the plant while it was not in rate base. Both should be recovered over the remaining useful life of the project. (MCC Exh. 4A, p. 29)

122. In his rebuttal testimony, Mr. Ball of MDU argued against Mr. Clark's proposed adjustments. Concerning Clark's proposed ceasing of deferred depreciation expense as of June 30, 1983, Mr. Ball offered the same response as he made regarding AFUDC as discussed in the rate base section of this Order. Ball testified, "In essence, Mr. Clark's proposal would deny, forever, the recovery of deferred depreciation expense already recorded on the Company's books pursuant to the Commission's last Order" (MDU Exh. UU, p. 7).

123. Concerning Clark's recommendation regarding the amortization of the deferred depreciation expense related to the disallowed portion of Coyote, Mr. Ball believed these costs should be reflected in rates over a time period equal to the time period over which investors were required to forego the reflection of such amounts in the cost of service, which is three years, as proposed by MDU. Ball stated, "To require amortization over the remaining useful life will inequitably prolong the recovery of this cost" (MDU Exh. UU, p. 7). Mr. Ball continued:

> Mr. Clark attempts to tie the additional AFUDC and deferred depreciation- expense together but does not recognize that the additional AFUDC, which is capitalized in accordance with regulations, is required to be recovered over the useful life of the property. Deferred items, however, are not necessarily subject to such requirements and amortization or recovery periods may be established that differ from the useful life. (MDU Exh. UU, pp. 7-8)

124. In accordance with the Commission's decisions in the rate base section of this Order, the Commission denies Mr. Clark's proposals to reflect the expense effect of reducing the AFUDC rate and stopping the accrual of AFUDC at June 30, 1983. Clark also proposed to reduce the unamortized deferred depreciation expense to its June 30, 1983 level. The Commission finds that this unamortized balance should be reflected through December 31, 1983, consistent with the accrued AFUDC treatment discussed in the rate base section of this Order. MDU is allowed to continue accruing unamortized deferred depreciation expense until this Final Order is approved, and the residual accrual (between January 1, 1984 and the approval date of this Final Order) will have to be handled as an item in a subsequent rate filing, the amortization of which should be filed in the same manner as determined by the Commission below. The Commission, therefore, approves an expense reduction for the depreciation of AFUDC in the amount of $26,934.

125. The main issue yet to be resolved concerning the proper treatment of the previously unreflected portion of the Coyote plant is the proper amortization period over which MDU can reflect in rates the related depreciation expense. MDU believes the proper amortization period is three years as a reflection of the period of time during which that portion of the Coyote plant was disallowed in cost of service. MCC favors amortization over the remaining useful life of the plant as a match with the treatment of accrued AFUDC. The Commission agrees with the approach presented by MCC. For ratemaking purposes, a portion of the Coyote plant has been determined, until now,~to be not used and useful; therefore, in the eyes of this Commission, the value of this plant at the time of completion, plus accrued AFUDC, should be the amount depreciated over the remaining useful life of the plant to reflect current recognition that the plant is now entirely used and useful. The unamortized depreciation, therefore, is similar to the accrued AFUDC regarding the amortization of their balances, and the proper amortization period for both of these balances is over the remaining useful life of the plant. The Commission, therefore, finds a reduction associated with the amortization of deferred Coyote depreciation expense in the amount of $302,609 to be proper in this proceeding.

<u>Captive Coal</u>

126. The Knife River Coal Company, 100 percent owned by MDU, provides the coal fuel supply to the Beulah, Heskett, Lewis and Clark, Big Stone, and Coyote generating plants. Concerning the Big Stone and Coyote plants, the coal supply contracts with Knife River were negotiated by the consortium of utilities, including MDU, which owned the plant. These contracts provide the coal prices MDU pays for its generating plant fuel supply, and it is these prices that MDU seeks to pass on to ratepayers as its captive coal expense.

127. The Montana Supreme Court addressed the Commission's duty to regulate a utility's expenses when those expenses are generated from a parent utility's subsidiary in Montana-Dakota Utilities v. Bollinger, ____Mont.____, 632 P.2d 1086, 38 St. Rptr. 1221 (1981),

> A function of the PSC, in fulfilling its duty to supervise and regulate the operations of MDU as an electric utility, is to see that MDU's rates are just and nondiscriminatory. Section 69-3-330, MCA. In complying with this obligation, it follows that the PSC must scrutinize and review the operating expenses of MDU to prevent unreasonable operating costs from being passed on to the customer. When one of the expenses submitted by MDU is caused transactions with a subsidiary company, the scrutiny applied by the PSC must be all the more intense. (emphasis added) 632 P.2d at 1089, 38 St. Rptr. 1224.

128. MCC witness, Dr. John Wilson, proposed an adjustment to eliminate the profit from the Knife River Coal Company which exceeded an equity rate of return of 15 percent. Dr. Wilson calculated that, in 1982, Knife River Coal Company earned income of $8.8 million and had average equity of $36.7 million, or a rate of return in excess of 24 percent (MCC Exh. 5A, Exh. TW-10, p. 1 of 2).

129. Dr. Wilson performed two studies which indicated to him that a proper rate of return for Knife River Coal should not exceed 15 percent (MCC Exh. 5A, p. 19). First, Dr. Wilson examined recent and projected rates of return for the six independent coal companies for which he could obtain public financial data. Second, Dr. Wilson performed a study of profit rates earned by unregulated firms throughout all industrial sectors of the U. S. economy. (MCC Exh. 5A, pp. 11, 14)

130. The results from both of Dr. Wilson's studies indicated that a proper rate of return for Knife River Coal would not exceed 15 percent. The related captive coal adjustment reflects what Dr.

Wilson professes to be a reasonable rate of return for the Knife River Coal Company based on MCC's "rate of return" methodology.

131. The Company's methodology concerning the captive coal issue was the "market price" approach. Mr. R.O.M. Grutle, Mr. Wallace W. Wilson, and Mr. W. W. Kroeber presented evidence that an independent, competitive coal market exists on which the consortium of utilities could have procured coal in lieu of entering into the Knife River contract, and that the terms of the Knife River contract, and the price paid pursuant to it, compare favorably with what would have been available on the open market. Mr. John P. Weir discussed his company's appraisal of the coal-mining properties of Knife River Coal Mining Company.

132. Mr. Grutle, a retired officer of Otter Tail Power Company (Otter Tail), testified concerning the operation of the Big Stone and Coyote plants, of which Otter Tail has the largest single ownership share of those facilities -- 47.5 percent of Big Stone and 35 percent of Coyote (MDU Exh. QQ, p . 1) . He stated that MDU did not negotiate with Knife River on the coal supply contracts for either Big Stone or Coyote generating stations (MDU Exh. QQ, p. 4). When asked why the consortium of utilities which owns both the Big Stone and Coyote plants entered into a coal supply contract with Knife River, Grutle answered that the consortium was able to negotiate the best long-term reserve commitment from the Knife River Coal Company (MDU Exh. QQ, pp . 3-4).

133. Mr. Weir is President of the Paul Weir Company, which specializes in mining, geology, and economics in connection with coal and minerals of similar occurrence, including the valuation and appraisal of coal properties and coal mining operations. MDU requested Mr. Weir's company to make such an appraisal to determine the recoverable quantity of coal and to determine the fair market value of that quantity (MDU Exh. OO, p. 3). Weir determined that the fair market value of the Knife River reserves is $0.15 per ton, or $85.4 million, and that a computation of a rate of return based upon Knife River's fair market value would constitute a reasonable method of determining its profitability (MDU Exh. OO, p. 4).

134. Mr. Wallace Wilson, an independent energy consultant, evaluated the financial performance of Knife River Coal Mining Company, including the reasonableness of the prices it charges MDU. He stated, "I conclude that Knife River Coal Mining Company operates in a very

competitive business area, and the prices it charges MDU for coal are just and reasonable and do not result in unreasonable profits." (MDU Exh. RR, p. 2)

135. Mr. Wilson believes quite strongly that there is a very competitive coal market for Northern Plains lignite. He listed four companies which operate mines having capacity to produce in excess of one million tons per year of Northern Plains lignite from mines in North Dakota and Montana. In comparing these four mines to Knife River, Wilson determined that all are comparable in terms of their lignite-producing capacity, but only the Baukol-Noonan operation would provide a valid comparison with Knife River, based on all aspects of operations. (MDU Exh. RR, pp. 3-5)

136. MDU witness Wilson rebutted MCC witness Wilson's study of six comparable coal companies. Wilson said that not one of the six companies, or the group as a whole, is representative of the entire domestic coal industry. He stated, "The financial performance of such a small group of companies does not and cannot have any particular significance for generalizing on the performance of the entire industry" (MDU Exh. RR, p. 6) Mr. Wilson also emphasized that most of Dr. Wilson's comparables should not be classified as independent coal companies, but rather as diversified companies in the coal business (MDU Exh. RR, pp. 6-12). As further evidence of poor comparability, Mr. Wilson testified, "Knife River produces only low-sulfur lignite coal from surface mines, whereas all six of the companies Dr. Wilson used for his sample ... produce large quantities of various grades of bituminous coal, nearly all from deep mines, at higher unit costs and subject to changing market conditions due to more widespread variations in demand"- (MDU Exh. RR, p. 12).

137. Concerning the diversified companies in Dr. Wilson's study of comparable coal companies, Mr. Wilson of MDU disagreed with the allocation computations performed by Dr. Wilson in determining the profitabilities for the six companies in his sample. Wilson disagreed with the method of allocating earnings on the assumption that they equate with earning assets. He believes Wilson's procedures are arbitrary, not subject to satisfactory proof, and are not valid for purposes of this Commission. (MDU Exh. RR, p. 13)

138. MDU witness Wilson determined that Baukol-Noonan, Inc. represents the only coal company that is comparable to Knife River because it produces only North Dakota lignite coal, does not own any noncoal operations, does not engage in coal brokering, operates two surface mines in

the same general area as Knife River, is subject to identical operating regulations and restrictions, competes for utility and industry markets in the same area as Knife River's marketing operations, and has generally comparable mining conditions. Wilson, therefore, proposed that for comparison purposes Baukol-Noonan should be used by this Commission in preference to the comparables used by Dr. Wilson of MCC. (MDU Exh. RR, p. 15)

139. MDU witness Wilson presented a comparison of coal prices at North Dakota and Montana lignite coal mines. He also made an analysis of Knife River's coal sales and prices during the last few years. The purpose of the study was to provide a breakdown of Knife River's coal sales, by volume and average price, for various categories of customers (MDU Exh. RR, pp. 17-19). By computing the cost per million BTU's (MMBTU) of heat, Wilson calculated Knife River's lignite coal price to MDU to be about 72 cents per MMBTU. Comparatively, the Colstrip station was paying Western Energy, a subsidiary of the Montana Power Company, about 84 cents per MMBTU for semibituminous coal. (MDU Exh. RR, pp. 17-21)

140. Mr. W. W. Kroeber of MDU also rebutted Dr. Wilson's testimony. He maintained that most of the coal sold by Knife River is not sold to MDU, and MDU owns only a 20 percent share of the Big Stone and Coyote generating stations. Kroeber continued:

> The coal supplied to those stations is sold under a contract negotiated with Knife River by Otter Tail Power Company, owner of the largest single interest in both stations. In order for Dr. Wilson's overcharge assumption to have any validity one must further assume that the other involved utilities, who have no interest in Knife River, are willing to overcharge themselves for the benefit of MDU. (MDU Exh. SS, p. 2)

141 Witness Kroeber discussed the coal market in North Dakota and said that there are five different coal mines in and around the Beulah area supplying coal to no less than six major generating stations. Concerning the Coyote plant, he stated, "They wanted to purchase coal from Knife River because Knife River offered contractual terms which no other company could match" (MDU Exh. SS, p. 2). He concluded that Knife River has not only priced its coal reasonably, but also more competitively than other companies (MDU Exh. SS, p. 3). In support of his statements, Mr.

Kroeber provided the results of his study which showed that Knife River's cost rate is very competitive in the coal market (MDU Exh. SS, pp. 4-6).

142. Knife River Coal Mining Company, a subsidiary owned 100 percent by MDU, earned approximately 22 percent in 1982 based on its year-end stockholders' equity. Since MDU stockholders own Knife River, they are, in effect, selling coal to the ratepayers of MDU which earns them this rate of return. This is a matter of concern to the Commission. The Commission finds this return evades the spirit of regulation. To quote Dr. Wilson of MCC, "The vertical integration by MDU into the coal mining business may provide the Company with an opportunity to circumvent effective return regulation by capturing monopoly profits in its affiliated upstream coal operations" (MCC Exh. 5A, pp. 4-5).

143. To parrot an example from page 24 of Order No. 4467 (MDU Docket No. 6567):

> What if MDU stockholders had decided to form a subsidiary corporation that would own all the electric generating facilities and sell the power to the utility parent? These facilities of course, would not be dedicated to the public convenience and would, therefore, not be regulated. Would MDU ratepayers be required to pay MDU stockholders (through the subsidiary) the going rate for electricity regardless of the rate of return being earned on these assets by the subsidiary?
>
> The Commission feels that the relationship between Knife River and MDU is akin to the above situation. The Commission will not attempt to regulate Knife River. However, simply because Knife River has been legally separated from MDU does not mean MDU's ratepayers should be subjected to excessive coal prices that would not otherwise exist if MDU and Knife River were a single corporation.
>
> The Commission's only method of protecting the ratepayers in this proceeding against these excessive prices is, of course, to limit the amount MDU will pay to Knife River for coal.

144. In making its decision, the Commission found weaknesses in both approaches used to determine the captive coal expense. The Company's "market approach" was fairly thorough. However, as explained on page 41 in Order No. 4714a of Docket No. 80.4.2, from the Department of Justice report "Competition in the Coal Industry":

> In practice, however, because of the nature of the coal markets, <u>identification of the appropriate competitive prices is virtually impossible</u>. Coal prices are not some broad national aggregate but are

> tied to a very specific location and quality factors. In addition, a significant portion of the steam coal is sold by long-term contract. Thus it may prove difficult to estimate an appropriate set of market prices to use to check a utility's accounting price of coal (emphasis added) (TR, pp. 47, 48 of Docket No . 80.4.2)

One of the very prominent weaknesses in the market approach is that coal from outside areas of the generating units require varying degrees of transportation and related costs which can greatly distort the comparability of using shipped coal versus a minemouth operation. Although the market may show the economic advantage of a minemouth operation, the relative comparability of the coal prices may be forfeited because of inordinate, dissimilar costs such as transportation.

145. In captive coal situations, a subsidiary of the utility is supplying coal to the utility as a result of a contract between the parent utility and its subsidiary. MDU maintains that the Knife River contracts for the Big Stone and Coyote plants were the result of arm's-length negotiations between Knife River and Otter Tail Power, as would normally be the case in a competitive market. As a result of the parent/subsidiary relationship in this very important aspect of electric utility operations, the Commission must scrutinize carefully the effects of all Knife River contracts involving MDU on the rates paid by the ultimate customers. The Commission must determine a reasonable level of coal expense much the same as it would determine any other operating expense of a regulated utility. The mere fact that MDU is a participating owner in the Big Stone and Coyote plants, which consume Knife River coal, necessitates that the Commission carefully scrutinize these coal costs that are being charged to MDU ratepayers. The Commission's major concern is the level of expenses that MDU's ratepayers are being reasonably charged.

146. Dr. Wilson's use of comparable coal companies to test the reason- ableness of a captive coal company's profits provides some useful guidelines for determining a reasonable level of profitability for Knife River Coal Company. There are, however, some problems with the comparability of companies used by Dr. Wilson. Perhaps most prominently, is his inclusion of eastern mining operations with characteristics significantly different from the Knife River operation. As Dr. Wilson pointed out, these problems are in significant part caused by the unavailability of public financial information for coal companies (MCC Exh. 5A, pp. 11-12).

147. The comparable companies study shows that a 15 percent return on equity does not appear to be an unreasonable level of profits compared to the somewhat lower average of 9.78 percent equity return for six companies who have substantial coal operations and whose financial statements are publicly available. For comparison purposes, the Commission included the adjusted 1982 Baukol-Noonan equity return figures[1] with Dr. Wilson's comparable companies study. The results show a composite average of 12.27 percent earned return on equity for the seven companies, a level still considerably below Dr. Wilson's recommended equity return of 15 percent.

148. Because of the difficulties inherent in finding truly comparable coal companies with which profit comparisons can be made, the Commission finds it reasonable, as a check to admittedly imperfect data, to look at other areas of the economy for profitability figures. Dr. Wilson presented evidence showing that other sectors of the economy earned between 10 and 11 percent on average

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[1] Baukol-Noonan's fiscal years end April 30 of each year; so, to get an approximate calendar year-end equity return, a weighted average is calculated:

1981 return 27.4%
1982 return 26.6%
1983 return 27.5%

1981 adjusted return: [27.4% (from 1981 above) X .33] + [26.6% (from 1982 above) X .67] = 26.86%

1982 adjusted return: [26.6% (from 1982 above) X .33] + [27.5% from 1983 above) X .67] = 27.2%

in 1982 (MCC Exh. 5A, JW-7, p. 1, JW-8, p. 1). Of even more significance in the Commission's opinion, is the profitability of corporations denoted as natural resource or coal companies on MCC Exh. 5A, JW-7 and JW-8. Page 1 of Exhibit JW-7 shows a 1982 equity return of 13.2 percent for petroleum and coal products companies. Exhibit JW-8 shows a 1982 equity return of 13.1 percent for natural resources (fuel) companies, down from 18.6 percent the previous year. On pages 2 and 3 of Dr. Wilson's Exhibit JW-8, he supplied an exhibit which listed the various companies making up the natural resources (fuel) section on page 1 of Exhibit JW-8. During the hearing, Dr. Wilson also listed the companies on this exhibit which have coal operations (TR, pp. 109-111). For those companies listing coal as - a marketed fuel, the average equity return - for 1982 was 12.43 percent compared to 14.99 percent in 1981. All these figures point to the reasonableness of Dr. Wilson's proposed Knife River equity return of 15 percent. The Commission is fully aware that an economic recession in 1982 causes industry return figures to decrease compared to 1981 figures. Since 1981 represents a more normal year economically, the 1981 equity return figure of 14.99 percent for natural resources (fuel) companies marketing coal compares favorably with Dr. Wilson's recommended coal profit level of 15 percent.

149. Again for comparison purposes, the Commission combined the adjusted equity return figures (refer to footnote 1 above) of Baukol-Noonan with those of the coal marketing companies in Dr. Wilson's natural resources (fuel) exhibit. The resulting 1982 average of returns on equity is 13.35 percent, a figure still well below Dr. Wilson's recommended return of 15 percent.

150. Mr. Weir of MDU suggested that a reasonable method of determining the profitability of Knife River would be to compute a rate of return based on the fair market value of Knife River's reserves (MDU Exh. OO, p. 4). Dr. Wilson of MCC disagreed with such a market value approach for determining a reasonable profit. Wilson testified:

> That approach to testing the reasonableness of profits on a utility's transactions with an affiliate would be circular and unreliable because the fair market value of the property is simply a capitalization of coal profits. Market value, therefore, does not provide an independent basis for testing either profits or prices....This calculated market value of the reserves, therefore, does not prove that the coal prices are fair in the first place, and it cannot provide an independent test of the

> reasonableness of the prices or the profits afforded by those prices.
> (MCC Exh. 5A, p. 10)

151. The Commission agrees with Dr. Wilson's above analysis. In computing Knife River's profitability, the Commission finds it proper to use the amount of Knife River's capitalization which closely matches the original cost valuation of its assets. This method of reporting is consistent with the financial reporting of all corporations, including natural resource companies.

152. As discussed earlier, the Commission has a duty to closely scrutinize the reasonableness of a regulated utility's expenses when those expenses are generated by a subsidiary of the parent utility. This parent-utility-subsidiary-coal supplier relationship exists between MDU and Knife River Coal Company, and affects the riskiness of the Knife River operation.

153. It is an axiom in the financial community that the determination of what a reasonable profit is depends to a large extent on the risk involved in that particular business. The higher the risk involved, the higher the profits that investors expect to compensate for their risk of loss.

154. Dr. Wilson claimed, in his direct testimony, that the Knife River Coal operation has relatively low risks due to its relationship to MDU, and the consequent protected market environment (MCC Exh. 5A, p. 16). The subsidiary enjoys the security of a captive market through its long-term contract with its parent MDU as purchaser, either through direct contracts or participation as a generating partner. MDU, on the other hand, enjoys a secure coal supply from the Knife River subsidiary, insulated in some instances from the high cost of coal transportation.

155. Dr. Wilson elaborated that an analysis of Value Line's safety, price stability, and earnings predictability indicates that the coal industry, as a whole, is only marginally more risky than other publicly traded firms. Additionally, captive coal operations are less risky than the coal industry due to the utility-sheltered aspect of these transactions (MCC Exh. 5A, pp. 17-18).

156. The Commission agrees with Dr. Wilson's risk analysis. Knife River should not be able to charge a coal price to MDU, to be paid by MDU's ratepayers, that reflects profits far above other coal operations and other natural resource companies, many, if not all, of which do not enjoy the risk reducing characteristics enjoyed by Knife River.

157. In determining a reasonable rate of return for Knife River, the Commission took into account many factors. In the Montana Power Company (MPC) Docket No. 82.8. 54, the Commission utilized the 1981 average of equity returns for natural resource (fuel) companies of 18. 6 percent as a reasonable return for MPC's coal subsidiary Western Energy. This return figure can be seen on page 1 of Exhibit JW-8. Because 1982 was a very poor year economically for the coal industry, the Commission feels the use of the 1982 equity return for natural resources (fuel) companies of 13.1 percent (MCC Exh. 5A, Exh. JW-8, p. 1 of 3) would be unreasonable as representing a normal coal return level. As a further refinement in this proceeding, the Commission believes that the returns of only those companies on pages 2 and 3 of Dr. Wilson's Exhibit JW-8 which Dr. Wilson identified as having some coal operations should be used in determining a reasonable profit level for Knife River. Furthermore, the Commission is including the adjusted 2 -7 return figures for Baukol-Noonan in this calculation. As a way of providing a more normal year return figure, the Commission finds the averaging of 1981 and 1982 equity returns for the above companies to be proper in this proceeding. The resulting equity return to be utilized in calculating Knife River's allowable profit level is 14.565 percent. This return figure compares very favorably to 1982 equity return figures for the industry categories of petroleum and coal products (13.2 percent), natural resources (fuel) (13.1 percent), and industries as a whole (11.0 percent).

158. The Commission believes that the most reasonable approach to calculating Knife River's return figures is to look at the actual results of operation. Because Knife River is an unregulated enterprise, it is improper to apply regulated-industry type adjustments to its financial statements. Knife River's net income for 1982 was $8,845,584 and its year-end equity was $40,244,132. The resulting 1982 return on equity j on a year-end basis, is 21.98 percent, a considerably higher level than the return level of 14.565 percent discussed above. The year-end figures for 1981 show a return on equity of 22.3 percent, only a slightly higher return level than 1982 even though the rest of the economy, including the coal industry, was suffering through a severe recession in 1982. This is a further fact which points to the necessity for making a coal expense adjustment in this proceeding.

159. The Commission finds that the above analysis indicates that a captive coal adjustment is proper in this proceeding. Based on all of the information presented, the Commission finds that the coal expenses claimed by MDU that reflect an approximate 22 percent profit level for Knife River in 1982 are excessive and should be reduced to reflect expenses that would yield an equity return to Knife River Coal Company of 14.565 percent.

160. In calculating the captive coal adjustment, the Commission finds the use of Knife River's actual 1982 year-end total stockholders equity to be proper in determining Knife River's allowable return and, thus, MDU's allowable Knife River coal expense. This approach is consistent with the Commission's preference for analyzing Knife River's actual profit levels without attributing ratemaking adjustments to Knife River's financial statements. Use of Knife River's actual year-end total equity provides consistency in comparing the equity return figures of Knife River and the various companies in the industry, including the natural resources (fuel) companies, whose figures are all based on year-end equity (TR, p. 107).

161. Dr. Wilson, in his calculation of the required adjustment to coal expense to reflect a 15 percent equity return for Knife River, proposed to utilize a tax multiplier based on the marginal Federal income tax level of 46 percent (MCC Exh. 5A, Exh. JW-10, p. 1 of 2). The Commission finds this approach to be a ratemaking type adjustment and, therefore, is improper in calculating the proper amount of captive coal adjustment in this proceeding. The Commission finds that the proper tax multiplier should be based on the ratio of actual 1982 Knife River taxes to actual net income to be consistent with the approach of utilizing actual results of operation in determining a captive coal adjustment. This decision is consistent with the approved tax multiplier utilized in calculating a captive coal adjustment in the Montana Power Company Docket No. 82.8.54. That approved tax multiplier was based on the ratio of actual 1981 Western Energy Company taxes to actual net income, as proposed by Dr. Wilson in that proceeding.

162. In calculating his proposed coal adjustment, Dr. Wilson utilized a ratio of the computed excess Knife River revenues to total Knife River revenues. This ratio was applied against MDU's proposed test year coal costs. The Commission finds this approach to be in error as it violates the Commission's intention of adjusting only those Knife River transactions involving MDU, either

directly or indirectly. By saying that a certain percentage of total Knife River revenues is excess, Dr. Wilson is going beyond the boundaries limiting this adjustment to MDU-related Knife River coal sales. This expense adjustment must only pertain to coal sales to Knife River's parent, MDU. The Commission finds, therefore, that the calculated excess revenue on coal sales to MDU must represent the theory that MDU's portion of Knife River excess revenues equals the ratio of Knife River sales to MDU compared to total Knife River sales. This decision is consistent with the method approved in the Montana Power Company Docket No. 82.8.54, as proposed by Dr. Wilson in that proceeding.

163. The captive coal adjustment in this proceeding is, therefore, calculated as follows:

			(000)
1)	Knife River 1982 Year-End Equity		$ 40,244
2)	Equity Return @ 14.565%		$ 5,862
3)	Actual Knife River 1982 Net Income		8,846
4)	Excess Knife River Net Income		$ 2,984
5)	Tax Multiplier (1)		x 1.4615
6)	Total Excess Revenue		$ 4,361
7)	MDU % of Knife River Sales (2)		x .2518
8)	Excess Revenue on Sales to MDU		$ 1,098
9)	Coal Tons Sold to MDU		1,542
10)	Excess Cost Per Ton (3)		$ 0.71
11)	Pro Forma Proposed Cost Per Ton (4)		10.13
12)	Approved Pro Forma Cost Per Ton	$ 9.42	
13)	MDU Production Cost Tons	1,542	
14)	Approved Coal Expense		$ 14,526
15)	MDU Proposed Coal Expense		15,622
16)	Approved Adjustment		$ 1,096
17)	Allocation Factor-Montana		x .31686
18)	Approved Adjustment to Montana		$ (347)

(1) (4,082 + 8,846) ÷ 8,846 = 1.4615
(Taxes + Net Income) ÷ Net Income = Tax Multiplier
Refer to MDU Response to MCC Data Request OT-1

(2) (6,668 + 6,535) 52,439 = .2518
Knife River MDU sales Total Knife River Sales
Refer to MDU Response to MCC Data Request OT-1

(3) 1,098 ÷ 1,542 = $.71
Line 8 ÷ Line 9

(4) 15,622 ÷ 1,542 = $10.13
MDU Proposed Coal Costs ÷ Coal Tons
Refer to MDU Response to MCC Data Request WWK-4

164. Based on the above calculations, the Commission finds a decrease to MDU's Knife River coal expense in the amount of $347,000 to be proper in this proceeding. The Commission's approach recognizes that price comparisons are not controlling in the analysis of affiliated transactions; rather, it is the cost of the commodity, including the element of return or profit, which must be examined.

165. The classification of coal reserve operations as a nonutility or utility function becomes important to electric ratepayers due to the different ratemaking treatments afforded to the coal fuel expense. It is not clear to the Commission why coal reserves of Knife River Coal Company should be considered a nonutility function with its ratemaking treatment based on comparable profits and prices. Public utilities are required to provide service at the lowest reasonable rate, and the Commission is required to allow rates that reflect the lowest reasonable costs. In view of those requirements, it is reasonable for the Commission to question why MDU's electric rates should not reflect that coal reserves held by its subsidiary, Knife River, should not be given rate base treatment for ratemaking purposes. If MDU had not formed Knife River, but had simply held its coal reserves as Plant Held for Future Use, the coal supplies would be expensed to MDU ratepayers at the cost of acquisition plus operation and maintenance costs.

166. The Commission, therefore, requests MDU to present evidence in its next electric rate case to address the issues raised in Finding of Fact No. 165. Failure to do so will be viewed as a failure to file a sufficient application.

Forecast Expense Adjustments

167. MDU has proposed certain forecast revenue adjustments for three expense categories as follows:

Expense Category	Montana Revenue Adjustment
Distribution	$ -19,415.0
Customer	15,452.0
Administrative and General	86,712.0
	$ 82,749

168. In forecasting the above adjustments MDU's objectives included: 1) maximizing the explanatory power of the models, and 2) avoidance of any initial forecasting of independent variables -- hence the autoregressive model structures.

169. The MCC proposed that the Commission deny MDU's forecast expense adjustments for three reasons: 1) the adjustments are not known and measurable; 2) the adjustments ignore offsetting productivity related cost reductions and future level of revenues; and 3) such adjustments are disincentives for MDU to operate efficiently.

170. The Commission finds several fundamental problems with the Company's forecast expense adjustments and rejects the proposals.

171. First, the Commission finds that such adjustments equate with built-in automatic adjustment clauses and as a result do not encourage efficient production practices; the Commission could, for example, approve of such an increase for 1983 and the Company could actually incur negative increments -- changes -- in expenses, such as occurred between the years 1973-1974 and 1976-1977 (for distribution expenses), and 1974-1975 (for A&G expenses).

172. Secondly, the Commission finds that the adjustments are simply not known and measurable. Acceptance of these adjustments are only appropriate if the Commission approved of a future test year: that is, the matching principle is violated.

173. Finally, the Commission simply does not have the resources to audit and certify the reasonableness of these forecast expense adjustments. Consideration of these expenses will have to wait until the 1983 forecast year (or a subsequent year) is a test year in a future electric revenue requirements docket.

Regulatory Lag and Attrition

174. The Commission recognizes that attrition can result from confiscatory and unreasonable ratemaking treatment. In an effort to minimize regulatory lag and the resulting attrition in this proceeding, the Commission allowed several ratemaking treatments which will prove to benefit MDU and greatly reduce potential attrition. For instance, to counteract regulatory lag, the Commission granted MDU an interim increase of $2,808,422 on December 12, 1983, approximately ten weeks after the Company's initial filing of this rate case. The Commission also notes that this electric filing has been processed within the nine month period required by 69-3-302, MCA.

175. Concerning attrition, the Commission in several instances in this proceeding allowed known and measurable changes which occurred after the end of the test year. Outstanding examples are the annualization of posttest year contractual labor expense increases, estimation of rate case expense, full reflection of the Coyote plant through December, 1983, and the updating of capital structure and costs. These post-test year allowances, among others, will greatly offset the negative effects of attrition. Concerning the Coyote plant, for instance, the Commission has used an historic test year, and the inclusion in rate base of all of the Coyote plant will allow future load growth and sales to be handled with existing reflected base plant. To the extent that load growth and additional sales do occur, this reflection of the total Coyote plant in the test year rate base will provide a counterbalance to any attrition which may arise as a result of the historic test year. The Commission also notes with interest that MDU used a 1982 test year but did not file the case until late September,

1983. The use of old test year data in itself can cause attrition, and MDU must take the responsibility for any attrition which results from the use of such an old test year.

176. Based on the above discussion and analysis, the Commission finds that very affirmative efforts have been made in this proceeding to minimize regulatory lag and attrition.

Revenue Requirement

177. The following table shows that additional annual revenues in the amount of $5,979,935 are needed by the Applicant in order to provide the opportunity to earn an overall return of 10.45 percent:

MONTANA-DAKOTA UTILITIES COMPANY
Revenue Requirement-Montana
1982 Test Year

	MDU Pro Forma	MCC Adjustments	Accepted MCC Adjustments	PSC Adjustments	Approved Pro Forma	Approved Increase For 10.45% Return	Approved Total
Operating Revenues	$24,905,848				$24,905,848	$5,479,935	$30,385,783
Expenses							
Fuel & Purchased Power	$ 8,039,042	$ (585,000)		$ (347,000)	7,692,0428		7,692,042
Other O&M	7,637,368	(171,368)	$ (130,312)	(36,212)	7,470,844		7,470,844
Total O&M	15,676,410	(756,368)	(130,312)	(383,212)	15,162,886		15,162,886
Depreciation	3,520,227	(395,523)	(23,739)	(329,543)	3,166,945		3,166,945
Taxes Other Than Income	1,349,250	(152,012)	(149,001)	(2,173)	1,198,076	$ 5,480	1,203,556
SIT & FIT-Current	(1,464,745)	491,300	143,754	178,577	(1,142,414)	2,717,793	1,575,379
Deferred Income Taxes	1,264,557	(4,714)	(4,714)		1,259,843		1,259,843
Investment Tax Credits	939,890				939,890		939,890
Amortization of ITC	(13,131)				(13,131)		(13,131)
Total Operating Expenses	$21,272,458	$ (817,317)	$ (164,012)	$ (536,351)	$20,572,095	$2,723,273	$23,295,368
Operating Income	$ 3,633,390	$ 817,317	$ 164,012	$ 536,351	$ 4,333,753	$2,756,662	$ 7,090,415
Amortization of Pre-1974 Gain	-0-	14,000			14,000		14,000
Total Operating Income	$ 3,633,390	$ 831,317	$ 178,012	$ 536,351	$ 4,347,753	$2,756,662	$ 7,104,415
Rate Base	$70,365,821	$ (3,643,969)	$ (632,152)	$(1,748,840)	$67,984,829		$67,984,829

Rate of Return	5.16%	6.40%	10.45%

PART E

COST OF SERVICE

178. Background. This Commission's most recent MDU docket (prior to the current) addressing electric cost of service issues was Phase II of Docket No. 81.1.2, Order No. 4799c. More recently the Commission considered and adopted a Service Charge in lieu of a Minimum Bill for just residential customers (Docket No. 83.1. 3).

179. Introduction. In the present docket MDU (Mr. John Castleberry) and the Montana Consumer Counsel (Mr. James Drzemiecki) submitted cost of service and rate design testimony. Mr. Fox also submitted rate design testimony on behalf of MDU. The findings below review the MDU and MCC proposals and set forth the Commission's decisions in the matter of Cost of Service and Rate Design. Cost of Service issues deal with the appropriate unit costs for three products: (1) energy, (2) demand (generation, transmission and distribution) and (3) customer. An additional cost of service issue deals with revenue reconciliation.

Cost of Service

180 Energy. MDU developed marginal running (energy) costs using the Stone and Webster MARGIN program. The results differ by cost period and voltage level of service, as summarized in Table 1 below:

TABLE 1

MDU'S MARGINAL RUNNING COSTS[1] (1982 Dollars)

	Cost Period (¢/kwh)			
Line No.	Summer		Winter	
1. Marginal Running Cost	2.492	2.061	4.691	2.760
2. Marginal Running Cost: Primary Service	2.912	2.372	5.241	3.141
3. Marginal Running Cost: Secondary Service	3.064	2.432	5.439	3.243

[1] Source: Exhibit No. JKC-5.

181. MDU's marginal running costs in Table 1 above (Line No. 1) are a six year average present value. MDU derived the resulting 1982 dollar estimate -- present value -- by de-escalating 1983-1987 running costs back to year 1982 using an average 5.441 percent escalation rate.

182. While running costs clearly vary by season, MDU proposes that rates differ by peak and off-peak cost periods only. In order to reflect seasonal cost differentials at least four rating periods would be required (winter, summer, spring and fall). This is due to the bimodal peak demand on the MDU system. The peak period includes the hours 8:00 a.m. to 10:00 p.m. Monday through Friday (the current peak period includes Saturday) . MDU also proposes to adjust the marginal running costs in Table 1 above (Line No. 1) by energy related Administrative and General (A&G) expenses and revenue requirements for working capital.

183. The MCC's marginal running costs also derive from MDU's MARGIN program. Rather than use a six year average in 1982 dollars, the MCC proposes to use the marginal running costs for year 1983 and in 1983 dollars. The MCC's cost periods for rates match MDU's. The MCC, however, excludes MDU's A&G and working capital related expenses.

184. The Commission accepts the use of the MARGIN program for purposes of computing marginal running costs. The six year average cost estimate (MDU's) is preferred to a single year (MCC's) estimate, but the average should be more current. While the first full year that the resulting cost-based rates will be in effect is 1985, the Commission finds that a four year average in 1984 dollars must be used. The four year average must be computed using the 13.915 percent discount rate used in its own analyses (see Data Responses JKC-16 and CWF-13 to the MCC). The resulting marginal running costs corresponding to those proposed by MDU (See Table 1 above) are summarized in Table 2 below; the Commission accepts and incorporates into these calculations MDU's proposed A&G, working capital and line loss adjustments.

TABLE 2
ESTIMATED MARGINAL RUNNING COSTS (¢/kwh)
(1984 Dollars)[1]

Line No.		Voltage Level/Cost Period			
		Primary		Winter	
1.	Marginal Running Cost:				
	Winter	5.3648	3.4927	5.5676	3.6064
	Summer	2.7734	1.8842	2.9182	1.9320
2.	Average Annual[2]:	3.248		3.367	
3.	Average On-Peak[2]:	4.064		4.238	
4.	Average Off-Peak[2]:		2.687		2.767
5.	Average Summer[2]:	2.247		2.334	

[1] The Marginal Running Costs on Line No. 1 are computed as the average (four year) discounted present value in 1984 dollars; the costs include MDU's A&G and working capital adders and MDU's voltage/seasonal specific line losses.

[2] The costs in each period were weighted by the corresponding number of hours in each period. The primary voltage on-peak (off-peak) winter and summer hours used in this weighting are 1,778 (2,590) winter and 1,792 (2,600) summer, respectively. The secondary voltage level hours are the same.

185. Generation Demand. MDU developed marginal generation related capacity costs using Stone and Webster's Alternative Scenario approach. This approach looks at the net savings of slipping the on-line date of the AVS No. 3 unit by one year. The net savings when divided by the concomitant reduction in peak load generates a $420.38/kw cost estimate. When levelized (with a nominal carrying charge) and adjusted (for General Plant, A and G, O&M expenses and Working Capital) MDU computed an estimate of $102.43/kw/yr. When adjusted for losses this figure increases to $114.94 and $108.19 respectively for generation capital costs at the secondary and primary voltage levels of service (there is no seasonal variation).

186. The MCC proxies the marginal cost of generation capacity with that of a combustion turbine. The resulting cost equals $348.0/kw. When levelized (with a nominal carrying charge), and adjusted for a 15 percent reserve margin and fixed O&M the cost equals $77.27/kw/yr (1983 dollars).

187. The Commission finds that the least cost source of capacity is correctly reflected by the cost of a combustion turbine (CT). MDU's own in-house benefit cost analysis also uses the cost of a CT to proxy the cost of generation capacity (See TR. pp. 355-356).

188. The Commission disagrees with MDU's and the MCC's use of nominal carrying charges in this docket. The Commission in other dockets has approved or required the use of real (economic) carrying charges (i.e. Pacific Power and Light Docket Nos. 82.4.28 and 83.5.36 and the avoided cost Docket No. 83.1.2). In the current Montana Power Company docket (Docket No. 83.9.67) all parties proffering long-run incremental cost studies also proposed the use of real carrying charges. The Commission finds that MDU should address this issue in its next electric retail case. Nominal carrying charges are accepted for purposes of levelizing generation, transmission and distribution related capital cost in this docket.

189. MDU must convert the MCC's cost per kw to 1984 dollars and make necessary voltage level loss adjustments (from Data Response JKC-31 to the MCC it is apparent that a 9.48 percent inflation adjustment was assumed to de-escalate 1984 costs to 1983).

190. Transmission Demand. MDU developed marginal transmission investment and related O&M costs by statistically regressing cumulative costs on cumulative peak demand (using 1974 to 1987 data). Investments excluded costs related to replacement facilities and remote baseload facilities. The resulting cost per kw equalled $437.44. When levelized and adjusted the cost equals $100.84/kw/yr (including related O&M costs). This latter figure, when adjusted for losses, results in annual secondary and primary marginal transmission costs of $113.16 and $106.51 respectively.

191. The MCC computes marginal transmission capital costs based on the cost to connect a CT to MDU's existing grid system. This cost equals $64.47/kw, or, $15.27/kw/yr when levelized and adjusted for fixed O&M and reserve requirements (1983 dollars).

192. The Commission finds that the MCC's cost per kw is appropriate. Such a cost is purely capacity related and necessarily excludes energy related costs. This cost should be adjusted, however, to reflect 1984 dollars (see Finding No. 189 above). In addition, this cost should be adjusted as necessary (voltage level of service) to reflect voltage level loss estimates.

193. Distribution Demand. MDU computes marginal distribution investment and related O&M cost components using different methods. The investment component is computed using the same technique used with transmission costs (i.e., regression analysis). The O&M component is computed by first splitting distributional expenses between demand and customer and then dividing annual distributional expenses by peak distribution demand; finally, a 6-year average cost is computed. The resulting investment and O&M related cost estimates equal $208.87/kw and $3.29/kw respectively. The former cost is annualized and added to the $3.29/kw O&M estimate resulting in a cost of $45.89/kw/yr. The resulting voltage level costs equal $49.94 (secondary) and $46.91 (primary).

194. The MCC developed distribution costs on an embedded cost basis. The MCC, however, classified certain costs between distribution- and customer-related differently (in the embedded cost study) than MDU (See Exh. MCC-1A, pp. 52-54).

195. The Commission finds the calculation of precise marginal distribution related costs problematic. The Company's approach is conceptually appealing. The MCC's proposal to allocate certain FERC accounts differently than MDU, while lacking rigorous support, also is appealing given the nature of the costs, i.e., poles, towers, fixtures, conductors, conduits and line transformers in FERC accounts 364 to 368. The MCC, however, does not develop unit marginal costs, but rather total costs which are in turn allocated to classes. The Commission consequently finds relatively more merit in the MDU approach. These costs must also be adjusted to 1984 dollars.

196. Customer Costs. MDU developed marginal customer costs on a "minimum investment" per customer basis using 1982 costs. These cost estimates vary by customer class (voltage level of service) and by metering costs. Table 3 below provides some of MDU's cost estimates.

TABLE 3

MDU'S CUSTOMER COSTS[1] (1982 Dollars)

Class (Voltage)/Rate	Cost/Month
Residential/10	$ 16.40
Residential/16	20.50
General Electric/20	170.95
General Electric/22	179.42
General Electric/23	175.32
General Electric/26	181.90
Industrial/30	600.38

[1] Source: Exhibit JKC-13, page 1 of 2

197. The MCC developed customer costs per class that reflect the costs of Services, Meters, Other Expenses and Direct Assignment. The following table summarizes the MCC's customer cost estimates for certain classes.

TABLE 4

MCC'S CUSTOMER COSTS (Estimated)

Class (Voltage)/Rate	Total[1] Costs	Total[2] Bills	Cost/Month
Residential/10	$2,009,405	255,322	$ 7.87
General Electric/20	309,132	36,619	8.44
General Electric/22	232,307	15,259	15.22
Industrial/30	3,260	238	13.69
Irrigation/25	3,812	74	4.29
Feed Grind/27	416	8	4.33
Municipal Pumping/48	9,755	100	8.13
Electric Water Heat/51	1,879	86	1.82

[1] Includes the summation of Service, Meter, and Other Expenses from Exhibit No. JD-3, page 3 (revised).

[2] From Exhibit Nos. JD-5, 6 and 7, and Data Response CWF-9.

198. The Commission finds the calculation of marginal customer costs to be problematic. Ideally, such costs would not be a tariff element, but rather an expense recovered via line extension charges when service is initially established. The Commission prefers the MCC's approach which identifies costs (e.g., services and meters) that are clearly customer related. Unit costs per class shall be developed per the method used in Table 4 above.

199. Note that the MCC's customer costs are disaggregated by voltage level of service (Exh. JD-3, p. 3). To the extent the number of customers is also available by voltage level (Data Response CWF-9 to the MCC provides no such breakdown), the cost of service revenue responsibility should also be disaggregated.

200. Because of the MCC's method of computing class specific customer costs, that of allocating total costs to classes via vectors, the higher costs of time-of-day (TOD) meters have not been accounted for. The Commission finds that, for purposes of cost of service, MDU should simply compute the differential in capital costs for a non-TOD and TOD meter; this difference should be annualized with its carrying charge of 19.191 percent and added to the MCC's cost allocation results. For example, the cost of a General Electric TOD meter (Schedule 20) equals $511.0; the cost of the non-TOD meter (Schedule 23) equals $250.0 (Exh. JKC-13, p. 2 of 2). It is the difference of $261.0 that should be annualized (actually put on a monthly basis) and added to the non-TOD monthly cost of $8.44 in Table 4 above.

201. Revenue Reconciliation. MDU's procedure involves multiplying unit long-run marginal costs per class by their respective billing determinants (See Data Response CWF-9 to the MCC). The summation of these total costs across all classes yields a total utility marginal cost based revenue requirement for Montana. Next, MDU divides the total embedded revenue requirement for Montana by the total utility marginal cost based revenue requirement. The resulting quotient is then multiplied by each class' total marginal cost based revenue requirement: That is, a uniform percentage reduction in class revenue requirement approach is applied. At this point, and prior to actual rate design, MDU makes three modifications to certain class revenue requirements (MDU Late Filed Exh. No. 9, February 20, 1984). The objective of these modifications is to moderate both revenue requirement increases and decreases to certain classes.

202. The MCC's revenue reconciliation proposal focuses on a subset of total marginal cost revenue requirements, referred to as "Bulk Power" costs. This subset of costs includes generation related energy and demand costs, and transmission related demand costs. The MCC's argument for this type of reconciliation is simply that Bulk Power costs are the costs that vary most by time of use (Exh. MCC-1A, p. 26). Like MDU, the MCC also proposed certain modifications to class revenue requirements.

203. The Commission finds that MDU's approach to revenue reconciliation is the preferred approach. The MCC's proposal to reconcile just Bulk Power costs does not work to maximize welfare. Clearly, the elasticity of demand is relatively larger for the energy and demand components of Bulk Power costs than for, say, customer costs. It follows that, from an economic viewpoint, one would attempt to minimize deviations from Bulk Power costs relative to, say, customer costs. While the reconciliation of the total marginal cost revenue requirement may not be theoretically optimal it is in the Commission's estimation preferred to the MCC's proposal.

204. MDU is to take the total revenue requirement from this docket of $30,385,783.0 and divide this amount by the total Company (Montana) marginal cost based revenue requirement. The resulting quotient must be used to scale back each class' marginal cost based revenue requirement.

205. Table 5 below summarizes the Commission's estimates of unit marginal costs that MDU is directed to refine and use in complying with this order. Both MDU's and MCC's proposed use of loss-of-load probabilities for developing peak-, off-peak costs, is accepted (See Exh. MCC-lA, p. 6 and Exh. CC, p. 4).

TABLE 5

THE COMMISSION'S ESTIMATES
OF UNIT MARGINAL COSTS

Cost Component/ Voltage Level	Cost Period			
	Primary		Secondary	
	Peak	Off-Peak	Peak	Off-Peak
Energy[1] ¢/kwh:				
winter	5.3648	3.4927	5.5676	3.6064
summer	2.7734	1.8842	2.9182	1.9320
Demand[2]:				
Generation & Transmission				
Primary		$ 97.75/kw/yr		
Secondary		$103.85/kw/yr		
Distribution				
Primary		$ 46.91/kw/yr		
Secondary		$ 49.94/kw/yr		
Total Demand[3]: Primary		$ 12.06/k2/mo		
Secondary		$ 12.82/k2/mo		
Customer[4]:				
Residential/10		$ 7.87/mo		
General Electric/20		$ 8.44/mo		
General Electric/22		$ 15.22/mo		
Industrial/30		$ 13.69/mo		
Municipal Pumping/48		$ 8.13/mo		
Electric Water Heat/51		$ 1.82/mo		
Irrigation/25		$ 4.29/mo		
Feed Grind/27		$ 4.33/mo		

Note: The above costs are not in the same year's dollars.

[1] See Table 2 above.
[2] See Finding Nos. 185, 192, and 193; the accepted costs were adjusted per MDU's loss estimates.
[3] Note total demand costs are approximate including a mix of 1982 and 1983 dollars.
4 See Table 4 above. Also, for Schedules 20 and 22 the cost , is a simple average of primary/secondary costs.

PART F

RATE DESIGN

206. Residential. MDU (Mr. Fox) proposed a number of changes to the time-of-day (TOD) Rate 16 and non-TOD (Rate 10) schedules. The TOD and non-TOD energy rates should both be flattened (both currently feature a 2-step inverted block structure with the break point at 300 kwh/mo.). The proposed TOD and non-TOD Base Rates respectively equal $3.00/mo. and $2.00/mo.

207. The MCC (Mr . Drzemiecki) developed flat and inverted-block nonTOD energy rates and a flat TOD energy rate. The Base Rate is $2.0/mo. in both cases. The MCC stated a preference for the flat energy rate proposal (TR, pp. 387-388).

208. At the satellite hearings, the question of flat versus inverted rates generated considerable comments. Proponents of the inverted rate structure, particularly Action for Eastern Montana, argued that the inverted structure v~as necessary to promote conservation, given the proper pricing signal to consumers, and to insure that consumption for essential electric uses would be at the lowest rate possible considering MDU's revenue requirement. Others, especially in Plentywood and Scobey, opposed inverted rates as they felt the Commission's initial block does not fully meet their essential needs, leads to large consumers subsidizing rates of the low income customers, and that the high cost of electricity already leads to consumers conserving to the best of their ability.

209. The Commission finds merit in the proposed flattening of the energy rates on both schedules. A weighted average marginal energy cost (weighted by the number of hours in each of four cost periods), based on MDU's marginal running costs at the secondary voltage level, equals 3.41¢/kwh (see Exh. JRC-1, p. 1 of 10, and MDU Data Response DBG-17 to the MCC).

210. The corresponding estimated cost based on the Commission's preferred discounting approach (in 1984 dollars and just four years of data) equals about 3.367¢/kwh. When estimated demand costs (Table 5 above) are added, at a 50 percent load factor, the combined energy and demand costs equal about 6.878¢/kwh. This cost is less than the current tail-block rate and greater than the current initial block; consequently, a flat rate seems reasonable. "A flat structure meets the Commission's concern of setting rates that will give the consumer the proper signal of the marginal cost of energy consumed. At this time, a flat structure will give the proper price signal and encourage conservation as the rates established in this docket approximate marginal costs."

211. The Commission's inverted rate structure currently in place may appear to be similar to the lifeline concept, but there are essential differences. There has been no cross subsidization of small consumption at the expense of large users. All residential consumers, regardless of age, income level, or consumption level

have benefited from the lower rates in the initial block. The Commission does find merit in the arguments presented by proponents of a flat rate in that such a rate design will meet the Commission's desire to set rates that reflect long-run marginal costs, is fair to all consumers, and its simplicity is easier for consumers to understand. The Commission concludes that a flat rate structure considering current revenue requirements will balance objectives of economic efficiency with concerns for fairness.

212. From Table 5 above a compensatory non-TOD Base Rate equals $7.87/mo. Consequently, MDU's proposed rates, while not compensatory, are accepted -- no further base year dollar adjustment is required. On each schedule the Base Rate related revenues should be computed and the balance of each schedule's revenue requirement collected via a flat cent/kwh rate.

213. On the optional TOD schedule a further adjustment is required. The present energy rate features a 100 percent differential between peak-and off-peak periods. The resulting TOD schedule should also feature a 100 percent energy rate differential.

214. General Electric: Non-Demand Metered. MDU proposed to replace the existing Minimum Bills on the TOD (Rate 20) and non-TOD (Rate 23) schedules with Base Rates of $10.00/mo.

215. The MCC proposed a lower Base Rate of $8.25 for each schedule.

216. From the Commission's analysis of cost characteristics for this class it is clear that rates on these schedules should be very similar to the corresponding residential rates. The Base Rate for each schedule, however, should be moderated to equal 50 percent of a 1984 dollar estimate. On a 1983 dollar basis the monthly cost equals $8.46 (using the MCC's costs from Exh.
JD-3, p. 3 of 4 and MDU's billing determinants from Data Response CWF-9 to the MCC). Then the Rate 20 Base Rate should equal $4.25 prior to being adjusted to 1984 dollars. The balance of Rate 20's revenue requirement should be recovered via a flat rate per kwh.

217. With one exception the Rate 23 Base Rate should be developed in a similar manner. The Rate 23 Base Rate should include an adder reflecting the annualized difference in meter costs for Rates 20 and 23. From MDU's testimony this difference equals $4.20/mo. in 1982 dollars (based on Rate 23's meter cost of $511.0 minus Rate 20's meter cost of $250.0, annualized with MDU's 19.191 percent distribution related carrying charge).

218. The existing on- and off-peak energy rate differential should be maintained at 100 percent. This charge will bring the rate differential in close alignment with the cost differential described in Finding 213 above.

219. General Electric: Demand Metered. MDU has also proposed a Base Rate ($14.00) for the non-TOD (Rate 22) and TOD (Rate 26) schedules. In addition, MDU proposed a voltage level energy rate distinction for just the TOD schedule.

220. The MCC also proposed Base Rates of $14.00 for the TOD and non-TOD schedules. The MCC, however, proposed voltage level energy rate distinctions for both the TOD and non-TOD schedules.

221. The Commission finds the following rate design appropriate for Rate 22. A Base Rate equal to 50 percent of cost (adjusted to 1984 dollars) should be tariffed. From the MCC's testimony (Exh. JD-3, p. 3 of 4) an adjusted Base Rate would then equal $7.50/mo.; note that this is a summation of primary and secondary voltage level customer related costs for Rates 22 and 26 divided by Rate 25 billing determinants (Data Response CWF-9 to the MCC).

222. The Commission finds appropriate the MCC's recommendation to differentiate energy rates by voltage level of service. The existing 4.482¢/k;;h energy rate should be frozen and applicable to secondary voltage level customers; the energy rate for primary voltage level customers shall equal 4.2579¢/kwh. The latter rate is reduced by 5 percent to reflect the voltage level differential in average annual energy costs from Table 2. Energy costs from this table indicate that this level is reasonable.

223. The remaining revenue requirement shall be recovered on a residual basis from the demand charge, but in two steps. First, the number of kw for which there is no charge shall be reduced from the existing 10 kw level until the revenue requirement for this class is recovered; the level shall not go below 5 kw per month, however. That is, at a minimum there shall be no charge for the first 5 kw per month. If a revenue requirement remains after lowering the number of kw for which there is no charge (up to 5 kw), then the existing rate of $2.25/kw shall be raised until the classes' revenue requirement is met. In no case shall the existing demand charge be lowered.

224. The Commission finds appropriate MDU's and the MCC proposal to differentiate energy rates by voltage level on Rate 26. The Base Rate for this class shall equal that for Rate 22 plus an adder equal to the annualized differential in meter costs. MDU's meter costs for Rate 22 ($656.0) and Rate 26 ($804.0), combined with MDU's distribution related carrying charge (19.191 percent) shall be used for this purpose. In unadjusted 1982 dollars this adder equals about $2.36/mo., for a combined Rate 26 Base Rate of $9.90/mo.

225. Given the energy costs in Table 2 above, the Commission finds necessary adjustments to the current on- and off-peak energy rates. First, the secondary voltage level on-peak energy rate should be lowered from the existing 5.878¢/kwh level to 4.482¢/kwh; the primary voltage on-peak rate shall be 5 percent lower,

or about 4.278¢/kwh. The Commission finds these adjustments necessary given the current marginal cost of energy.

226. The current off-peak energy rate is not so removed from current energy costs. Consequently, the existing rate of 2.939¢/kwh shall be the secondary voltage level off-peak energy rate; the primary voltage level rate shall equal 2.854¢/kwh, or 5 percent less.

227. Demand charges shall be computed on a residual basis identically to direction in Finding No. 223 above for Rate 22.

228. Private Lighting. MDU proposed no interim or final increase for the Private Lighting (Rate 24) schedule.

229. The MCC proposed a rate reduction to 5.877¢/kwh from the existing (interim) level of 9.685¢/kwh.

230. The Commission finds that, given the current costs of energy (3.542¢/kwh estimated for the secondary voltage level) and demand, and the MCC's finding of no customer cost (Exh. JD-3, p. 3 of 4 revised), the existing interim rate should be frozen.

231. Irrigation. MDU proposed a number of rate design changes to the Irrigation Schedule (Rate 25) including: 1) a Base Rate of $14.0/mo.; 2) a Demand Charge of $10.0/hp/season of connected load; 3) an Energy Rate of 3.6374/kwh; and 4) a Minimum Seasonal Charge of $20.91/hp of connected load but not less than $209.10. These rates assume the final revenue requirement as requested by the Company.

232. The MCC proposed the following rates: 1) a $10.00/mo. Base Rate; 2) an Energy Rate of 5.272¢/kwh and a Demand Charge of $1.0/hp/mo . of connected load.

233. The Commission finds the following rates appropriate. First, in order to bring this class' Base Rate more in line with that for Rate 22 a Base Rate of $7.50/mo. shall be tariffed. This rate is less than that proposed by either MDU or the MCC, but greater than the MCC's own cost result of $4.30/mo . ($3,812.00 of customer related costs from Exh. JD-3 p . 3 of 4 divided by MDU's estimate of 74 customers on Data Response CWF-9 to the MCC).

234. The energy rate for this class should be raised from the existing 2.171¢/kwh level to 2.334¢/kwh. This latter rate is the weighted average on- and off-peak secondary voltage cost for the summer months from Table 2 above.

235. The current demand charge equals $8.50/hp per season of connected load or roughly $2.23/kw/mo. ($8.50 divided by the product of 5 months and .746 percent -- the percent of one kw that a horsepower represents). Consequently, a Demand Charge on a dollar per kw basis shall be the residual rate

element for purposes of insuring this classes' revenue requirement is generated. The Commission would note that a demand charge up to $12.82/mo. is justified from the demand costs summarized in Table 5.

236. Note in Finding No. 262 below the Commission responds to MDU's proposed optional irrigation rate schedule.

237. Feed Grinding. MDU proposed no interim or final rate change for the Feed Grinding (Rate 27) schedule.

238. The MCC also proposed to not change this class' revenue requirement and indicated a 47 percent revenue reduction is supported. The MCC proposed that the difference between the frozen revenue requirement and the marginal cost revenue requirement be used to reduce (subsidize) the Electric Water Heating Schedule's (Rate 51) revenue requirement.

239. The Commission finds appropriate a number of rate changes. First, a Base Rate equal to $7.50/mo. shall be tariffed (and also adjusted to 1984 dollars). This rate, while greater than the MCC's customer cost estimate of $4.33/mo., reflects the customer costs this class would incur if there were only residential, general service, and industrial rate schedules.

240. The Commission finds that the Feed Grind energy rate of 5.463¢/kwh exceeds cost by an unacceptable amount. Rather than set the energy rate at cost, it should be lowered to the frozen rate of 4.482¢/kwh for demand metered secondary voltage General Electric customers.

241. The Demand charge for this class should be computed residually. The current two-step declining block structure should be replaced with a single flat-rate Demand Charge. The current Demand Charge Minimum Bill provision is also eliminated.

242. Mandatory Industrial TOD. MDU proposed several rate changes for this schedule (Rate 30) including: 1) a Base Rate of $14.0 (in lieu of an existing $11.50 Minimum Bill); 2) a single $3.0/kw demand charge; and 3) voltage level differentiated energy rates.

243. The MCC's proposals include: 1) a $13.50 Base Rate; 2) Demand Charges that vary by voltage level ($3.00/kw Primary and $0.75/kw secondary); and 3) voltage level differentiated energy rates.

244. The Commission finds that a Base Rate of 50 percent of the MCC's cost estimate (50 percent of roughly $14.00) plus an adder reflecting the annualized differential in meter costs should be tariffed (adjusted to 1984 dollars). The adder should be computed as the difference between a Rate 30 meter cost (12,071.0) minus the Rate 22 meter cost ($656.0) annualized, once more, with the Distribution related carrying charge of 19.191 percent. Before adjustment to 1984 dollars a $30.0/mo. Base Rate should be tariffed.

245. The current Rate 30 energy rates equal 4.7894¢/kwh on-peak and 2.395¢/kwh off-peak. The Commission finds that these energy rates should be replaced with those reflective of current costs on Table 2. The primary voltage level on- and off-peak rates shall equal 4.064¢/kwh and 2.687¢/kwh; the corresponding secondary voltage level rates shall equal 4.238¢/kwh and 2.767¢/kwh respectively.

246. The Demand charge shall be computed residually. Given the similarity in voltage level demand costs from Table 5 the Commission denies the MCC's proposal to tariff Demand charges with an eightfold difference ($3.0/kw/mo. for primary voltage and $0.75/kw/mo. for secondary voltage).

247. Municipal Lighting. MDU simply proposed an increase in this schedule's (Rate 41) rate per kwh. Additionally, the Company proposed to include text changes making this schedule available to highway lighting.

248. The MCC proposed that this single schedule be split into two separate schedules, one for Company-owned street lights and the other for customer-owned.

249. The Commission finds both proposals acceptable. The availability section of the tariff should include highway lighting. Also, the Company is to split up the schedule with separate rates per kwh for Company- and customer-owned street lights.

250. The combined revenue requirement for the Company and customer-owned street lights should first be reduced by the revenues currently generated by the Company's contract rental charges to customers using Company-owned street lights. This annual revenue requirement should be divided by kwh sales to customers using Company-owned street lights: that is, the differential in rates for the bifurcated light schedule should simply be the rental charge revenues derived from Company-owned street lights. This differential is an adder (to the Company-owned street light energy rate) to the otherwise flat rate per kwh for both light schedules.

251. The Commission finds no merit in the existing discount rate offered to Municipal Lighting customers. In the aggregate, residential customers offer equal stability, in terms of loads, for the Company. All existing discounts should be abrogated and the offering eliminated from the tariff.

252. Finding No. 265 below responds to MDU's High Pressure Sodium Vapor (HPSV) conversion analysis.

253. Municipal Pumping. MDU proposed increasing all rate elements for this schedule (Rate 48) except for the Minimum Bill which would be replaced by a $13.30/mo. Base Rate.

254. The MCC proposed a Base Rate of $8.00/mo. and a Demand Charge of $2.00/hp/month (MDU's Demand Charge proposal equalled $2.22/hp/mo.).

255. The Commission finds the following changes appropriate. First, a Base Rate equal to 50 percent of the MCC's estimated cost ($8.13/mo.) should be tariffed. The energy rate should be set at the current cost of 3.367¢/kwh, and the remaining Demand charge computed residually.

256. The Commission has the same criticisms of the existing discount rate offering to the customer class. The existing discounts should be abrogated and the provision removed from the tariff.

257. Controlled Electric Water Heat. MDU proposed to replace this schedule's Minimum Bill with a Base Rate of $1.50/mo. In addition, MDU proposed to eliminate the Demand Charge provision of the existing Minimum Bill, resulting in a rate/kwh for demand and energy.

258. The MCC's proposals are the same as MDU's except for the level of the rate/kwh. The MCC, however, proposed a reduction in this classes' revenue requirement equal to the decreased revenue requirement that is justified based on marginal costs for the Feed Grind Customer class.

259. The Commission finds that a Base Rate of $1.50 is appropriate. The balance of the classes' revenue requirement should be recovered residually via a flat energy rate.

PART G

OTHER ISSUES

260. Mandatory Time-of-Day Irrigation Rates. In Order No. 4799c (Docket No. 81.1.2) the Commission directed MDU to examine mandatory TOD rates for irrigation customers. In October, 1983, the Commission received MDU's compliance study.

261. MDU's analysis indicates that a mandatory rate would penalize a majority of its irrigation customers . Other regulatory agencies control the amount and rate of water extraction by irrigators thereby limiting an economic response to TOD rates.

262. The Commission finds merit in MDU's analysis. In lieu of the mandatory rate option the Commission finds acceptable the optional TOD rate option proposed by the Company (See Data Response CWF-12 to the Commission).

263. High Pressure Sodium Vapor Conversion. In July of 1983 the Commission requested MDU to perform a cost-effectiveness analysis for converting Company-owned street lights to HPSV.

264. In November of 1983 MDU submitted its analysis complying with the Commission's request. The results indicate that HPSV conversion is uneconomic given conversion costs and associated benefits.

265. The Commission accepts the Company's findings, but notes the following. First, it is clear that a majority of MDU's lamps are of the Mercury Vapor type which clearly constrains the cost-effectiveness of

HPSV conversion. However, it is also clear to the Commission that at least two of the assumptions in the Company's analysis bias the results: 1) the Company uses 4,000 hours of burn compared to 4, 200 hours used elsewhere in the Northwest (e.g., BPA and the Montana Power Company) and 2) the assumed HPSV replacement wattages for a given Mercury Vapor or Incandescent lamp exceed those used by, for example, the BPA. This latter assumption inflates the costs of conversion and underestimates the savings. It is not clear to the Commission, however, that lower wattage HPSV replacements would result in a positive cost-effectiveness test.

266. Finally, the Commission finds that the Company should grandfather the existing offering of Incandescent and Mercury Vapor lamps on its (Company-owned) street light systems. Future installations should be HPSV.

267. Miscellaneous Tariff Revisions. The Commission approves of the Company's proposals to:

1) add a listing of rules and regulations to the electric tariff table of contents;

2) separate the gas and electric rules by deleting reference to gas operations in certain rules;

3) substitute the word "rate" for the word "schedule" in Rule 101; and

4) delete item number 5 in Rule 117 dealing with fuse replacements up to 100 amps, as an available service provided by MDU.

CONCLUSIONS OF LAW

1. The Applicant, Montana-Dakota Utilities Company, furnishes electric service to consumers in Montana, and is a "public utility" under the regulatory jurisdiction of the Montana Public Service Commission. §69-3-101, MCA.

2. The Commission properly exercises jurisdiction over the Applicant's rates and operations. §69-3-102, MCA, and Title 69, Chapter 3, Part 3, MCA.

3. The Commission has provided adequate public notice of all proceedings and opportunity to be heard to all interested parties in this Docket. Title 2, Chapter 4, MCA.

4. The rate level and rate structure approved herein are just, reasonable, and not unjustly discriminatory. §69-3-330, MCA.

ORDER

1. The Montana-Dakota Utilities Company shall file rate schedules which reflect increased annual revenues of $5,479,935 in lieu of, rather than in addition to, interim rates. The total annual electric revenues of Montana-Dakota Utilities Company will be approximately $30,385,783.

2. All motions and objections not ruled upon are denied.

3. MDU shall design rates to generate authorized revenues which are consistent with the Findings of Fact entered by the Commission in this Order. The following tersely summarizes the Commission's direction:

a) Marginal running costs shall be developed using MDU's MARGIN program; Demand costs, except for Distribution related, shall reflect the Montana Consumer Counsel's (MCC) results. Customer costs except for TOD meter cost differentials shall reflect the MCC's cost results. All costs should be in 1984 dollars (the assumptions made for the 1984 dollar adjustments must be documented in working papers).

b) Base Rates shall be established in place of Minimum Bills on most schedules.

c) Voltage level rate distinctions shall be tariffed on Rates 22, 26, and 30.

d) Residential energy rates (Rates 10 and 16) shall be collapsed to a flat rate from the existing inverted structure.

e) The existing two-to-one (100 percent) peak-, off-peak energy charge differential shall be maintained per the Findings of Fact in this order.

f) The discount provisions for Rates 41 and 48 are eliminated.

g) The current Municipal lighting schedule shall be bifurcated into two separate schedules.

h) The Commission accepts MDU's proposed optional TOD irrigation schedule.

4. In submitting tariffs complying with this Order, MDU shall also submit detailed working papers detailing billing determinants, final rates, and revenues generated for the existing and resulting rate design of each class.

5. MDU shall provide the Montana Consumer Counsel's witness Mr. James Drzemiecki copies of all resulting tariffs and workpapers also provided to the Commission staff.

6. This Order is effective for services rendered on and after July 2, 1984.

DONE AND DATED this 2nd day of July, 1984, by a vote of 3 - 0.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION.

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THOMAS J. SCHNEIDER, Chairman

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HOWARD L. ELLIS, Commissioner

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DANNY OBERG, Commissioner

ATTEST:

Madeline L. Cottrill
Secretary

(SEAL)

NOTE: Any interested party may request the Commission to reconsider this decision. A motion to reconsider must be filed within ten (10) days. See ARM 38.2.4806.